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Robust market-based battery energy storage management strategy for operation in European balancing markets

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ABSTRACT

We present a robust battery energy storage system (BESS) management strategy for simultaneous participation in frequency containment reserve (FCR) and automatic frequency restoration reserve (aFRR) provision with market-based state of charge (SOC) restoration exclusively via intraday market. The study is motivated by the developments and harmonisation of the regulatory framework of European balancing markets and the rapidly increasing role of BESS in power system regulation. The proposed strategy involves BESS SOC restoration through scheduled transactions in the intraday market. It also includes reserve mode and recovery status management benefiting from regulatory alleviations granted to FCR providers that are qualified as limited energy reservoirs, and voluntary aFRR energy bid preparation process. Altogether, the management strategy is based on a worst-case activation anticipation approach, meaning that non-delivery of contracted reserves is under no circumstances permitted. Moreover, activation overfulfilment and FCR deadband utilisation are not allowed for battery charge restoration in line with the recent regulation. The strategy is particularly useful for balancing reserve providers that do not have options to restore the BESS energy content within their own portfolio, thus having to rely on wholesale markets, which can have significant lead time before trade delivery. Based on simulations, we first validate the robustness of our strategy in an extreme worst-case scenario and then provide case studies utilising power system operational data from Germany and Finland, showcasing the technical and economic performance of the devised strategy under realistic and diverse conditions. While our approach builds on the upcoming Baltic balancing market framework, due to the ongoing European balancing market harmonisation, it is applicable also to the EU markets in general.

1. Introduction

1.1. Background and motivation

1.1.1. Storage needs

There has been a rapidly growing need for energy storage as the share of weather-dependent renewable generation within the power systems is continuously increasing, which in turn requires improved flexibility. While pumped-storage hydropower is the most widely used storage technology in terms of capacity, grid-scale batteries have seen the largest growth lately. For example, in the European Union (EU), the amount of new additions of grid-scale battery storage has more than doubled both in 2021 and 2022 compared to the year before [1], and a huge ramp-up of storage deployment is expected as >200 GW and >600 GW of storage capacity will be needed by 2030 and 2050 respectively (from ~60 GW in 2022) in order to meet the ambitious EU climate goals. More than 100 GW of this capacity in 2050 could comprise stationary electrochemical batteries [2].

1.1.2. EU regulatory requirements for LERs

Already now, battery energy storage systems (BESS) as a short-term flexibility source account for a significant share of frequency containment reserve (FCR) providers in Europe and elsewhere [3] due to relatively high potential revenues, fast response and high flexibility of BESS, which is particularly suited for the primary frequency control [4–6]. To facilitate FCR provision by storage systems, the EU System Operation Guideline (SOG) [7] specifies particular conditions for limited energy reservoirs (LERs), defined as storage units that can be depleted within 2 h of operation without an active energy reservoir management [8] and thus could include, e.g. electrochemical, compressed air and pumped hydro storage [9]. During power system normal state, an FCR-providing

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Nomenclature

Variables

$\Delta E_{\text{s.d.}}\ (t)$	BESS self-discharge losses (MWh/Δt)
$\Delta f(t)$	frequency deviation at timestep t (Hz)
$\Delta f_{\max}$	frequency deviation for full FCR activation (Hz)
$\Delta f_s(t)$	frequency deviation at time t in worst-case scenario s (Hz)
Δt	simulation timestep (min)
$\Delta t_{\text{FRR,GCT}}$	aFRR energy market GCT before delivery period (min)
$\Delta t_{\text{ID,GCT}}$	ID market GCT before delivery period (min)
Δt_{LA}	duration of the look-ahead horizon (min)
$\Delta t_{\text{max.rec.}}$	the calculated maximum time for LER SOC recovery (min)
$\Delta T_{\text{max.rec.}}$	the allowed maximum time for LER SOC recovery (min)
ΔT_{minLER}	the minimum full activation duration LER FCR providers must withstand (min)
Δt_{MTU}	duration of an MTU (min)
Δt_{prep}	bid preparation time (min)
$E_{\text{av.DOWN}}$, $E_{\text{av.UP}}$	available energy for down- and up-regulation (MWh)
$E_{\text{LER,FCR,DOWN}}$, $E_{\text{LER,FCR,UP}}$	worst-case down- and up-regulation FCR energy required for a LER (MWh)
$E_{\text{worst,DOWN}}$, $E_{\text{worst,UP}}$	total worst-case down- and up-regulation energy required (MWh)
$k_{\text{FCR}}(t)$	FCR full activation equivalent (%)
$P_{\text{ch.av.}}$, $P_{\text{disch.av.}}$	BESS power available for charging and discharging (MW)
$P_{\text{ch.max}}$, $P_{\text{disch.max}}$	maximum BESS charging and discharging power (MW)
$P_{\text{FCR}}(t)$	contracted FCR capacity at time t (MW)
$P_{\text{FRR,DOWN,mand}}(t)$, $P_{\text{FRR,UP,mand}}(t)$	capacity of mandatory FRR down- and up-regulation energy bid valid at time t (MW)
$P_{\text{FRR,DOWN,vol}}(t)$, $P_{\text{FRR,UP,vol}}(t)$	capacity of voluntary FRR down- and up-regulation energy bid valid at time t (MW)
$P^*_{\text{FRR,DOWN,vol}}(T_{\text{FRR}})$, $P^*_{\text{FRR,UP,vol}}(T_{\text{FRR}})$	preliminary capacity of voluntary FRR down- and up-regulation energy bid for MTU T_{FRR} (MW)
$P_{\text{ID}}(t)$	capacity of ID market transaction at timestep t (MW)
s, S	index and set of FCR worst-case activation scenarios
SOC	BESS state of charge (%)
$SOC_{\max}$, $SOC_{\min}$	BESS maximum and minimum state of charge (%)
t^*	exhaustive worst-case enumeration loop helper timestamp
t, T_{FRR}, T_{ID}	index and sets of timestamps within a particular FRR bid validity period and ID delivery period
t, T_{LA}	index and set of timestamps within a particular look-ahead horizon
$T_{\text{FRR,GCT,next}}$	set of timestamps indicating the FRR validity period with the closest GCT
$t_{\text{FRR,start}}$, $t_{\text{FRR,end}}$	start and end timestamps of a particular FRR bid validity period
$t_{\text{FRR,vol}}$	timestamp at which a voluntary FRR energy bid decision has to be made
$t_{\text{ID,decision}}$	timestamp at which an ID bid decision has to be made
$t_{\text{ID,GCT,next}}$	timestamp at which an ID bid decision has to be made
$t_{\text{ID,start}}$, $t_{\text{ID,end}}$	start and end of particular ID trade delivery period (timestamp)
t_{now}	timestamp of the current timestep in the simulation
η_{ch}, η_{disch}	charging and discharging efficiency (%)

Acronyms

BESS	battery energy storage system
BRP	balance responsible party
CE	Continental Europe
DA	day-ahead
DE	Germany
DOF	degree of freedom
EU	European Union
FCR	frequency containment reserve
FI	Finland
FR	fast reserve
FRR	frequency restoration reserve
GCT	gate closure time
ID	intraday
ISP	imbalance settlement period
LER	limited energy reservoir
MTU	market time unit
RR	replacement reserve
SOC	state of charge
SOG	system operation guideline
TSO	transmission system operator

LER should be able to continuously activate FCR. However, during alert state, a LER shall ensure a full FCR activation for at least 15–30 min. A specific value for the minimum activation period (ΔT_{minLER}) needs to be proposed by the transmission system operators (TSOs) of each synchronous area based on cost-benefit analysis results. Continental Europe (CE) TSOs lean towards a 30-min ΔT_{minLER} (at least for new storage plants), but the final proposal is still under development to be submitted to the national regulators by the end of 2024 [10].

Nevertheless, CE TSOs have already devised a number of additional properties of FCR, including requirements for LER FCR providers [8]. Importantly, TSOs have now disallowed overfulfilment or dead-band utilisation, which means LERs should rather use, for instance, market-based measures for their reservoir restoration such as intraday (ID) trading. This is a significant contrast to previous work where degrees of freedom were suggested for state of charge (SOC) restoration and allowed within the regulation, especially in the UK and Germany [11], meanwhile reducing the energy needed for SOC management [12,13].

Furthermore, the CE TSOs require an active battery management strategy for LERs to ensure a valid SOC range and comply with ΔT_{minLER} and other requirements at all times [5,8]. To that end, we fill the gap of the previous studies by proposing and validating an active energy reservoir management strategy for an FCR-providing BESS respecting the prohibition of delivery overfulfilment, dead-band utilisation and considering ΔT_{minLER} as well as the reserve mode. The latter implies that during prolonged alert state (i.e. during long-lasting frequency deviations), after fulfilling the ΔT_{minLER} criterion, LER should react only to the short-term frequency deviation to continue contributing to power system balancing before full reservoir depletion [8]. Moreover, our strategy successfully implements market-based storage restoration exclusively in the ID market disallowing intentional imbalance in line with the recent EU rules.

1.1.3. *BESS role in the Baltic context*

LERs as FCR providers are of particular interest for the Baltic power system, which is scheduled to synchronise with CE network and disconnect from the Russian and Belarusian power grid by February 2025 [14]. Thereafter, the Baltic TSOs must be able to cover their FCR and other reserve needs themselves, whereas historically the primary frequency control has been ensured by the neighbouring Russian power system [15]. Hence, several large-scale BESS projects are under development in the Baltics to ensure power system reserve adequacy [16], including an 80 MW/160 MWh BESS to be owned and operated by the Latvian TSO for up to ∼3–5 years following a regulatory derogation [17]. To that end, the specific BESS is not operated for profit maximisation and is meant to securely ensure TSO reserve requirements until the regulator assesses that this can be achieved by regular (commercial) reserve providers actively participating in the balancing markets. Consequently, the challenges brought forward by the unique Baltic synchronisation project along with the EU-level regulatory framework evolution have motivated us to develop an efficient market-based BESS operational management strategy for reserve provision considering the future Baltic balancing market design and specific local conditions as well as the relevant EU regulations. Nevertheless, the study is applicable not only to European balancing markets but also for primary frequency control provision by BESS in general.

1.2. Literature overview and contribution

1.2.1. BESS management for FCR and FRR provision

Although there have indeed been a number of papers simulating FCR provision by BESS, e.g. in the German [5,12,18,19], Italian [11], Finnish [20] and Baltic market context [21], their primary approach for SOC management usually involves optimal utilisation of degrees of freedom (DOF), e.g. overfulfilment or deadband, as the regulatory framework has previously allowed deviating from proportional frequency control in specific cases, usually with no or little cost compared to scheduled transactions in the ID market [12,18,21]. Additional options previously considered for SOC restoration are bilateral trading and scheduling transactions within the same portfolio [5]. To that end, we contribute to the current body of knowledge by proposing a particularly robust battery management strategy which fully conforms to the recently imposed constraints on SOC restoration, carrying it out via the ID wholesale market only. To the best of our knowledge, this is the first study that investigates exclusively ID market-based BESS SOC management for FCR provision and considers also the recent EU regulations for FCR provision by LERs.

Moreover, our algorithm is devised such that it accepts adjustable ID lead time as an input parameter, which is important considering the potential future changes as the market design evolves. The strict requirements also stem from the fact that the BESS simulated in our case study will be owned and operated by the TSO as a back-up resource for reserve provision in case regular market participants cannot deliver it. Hence, own portfolio optimisation is not applicable and intentional imbalance or non-delivery of the committed reserves is strictly prohibited. While introduction of TSO-owned storage resources can be considered quite unique within the evolving EU electricity market landscape, this niche application and exceptional implications comprise another novelty of our paper. Instead, the existing literature usually focusses on optimising the BESS operation from its owner's perspective, aiming to maximise their profit whereas our objective is to robustly ensure reserve delivery.

In contrast to the primary control reserve or FCR service, secondary and tertiary control such as the aFRR (automatic frequency restoration reserve) and mFRR (manual frequency restoration reserve) has been dominantly provided by conventional power plants [4]. This is evident also from our literature search: there were 54 papers[1] dealing with BESS and FCR provision specifically, whereas BESS and either type of FRR was studied in 23 papers.[2] While those results are non-exhaustive and limited to the search strings used, there is a clear trend of employing BESS for FCR provision primarily due to their instantaneous response and the symmetric characteristics of FCR.

Only a few papers so far have focussed on BESS operational strategies with exclusively or partially market-based SOC restoration approach via the wholesale (ID) market. For example, when searching the *Scopus* database for papers on BESS strategies/algorithms for frequency regulation including keywords “market AND intraday”, only 13 papers[3] can be found. With that in mind, in our literature analysis, we have mostly focussed on papers studying BESS operation for FCR and FRR provision and, preferably, including market-based SOC restoration.

As concerns battery storage utilisation for FRR, Merten et al. proposed an optimised bidding strategy to estimate the revenue potential of a BESS (either standalone or in conjunction with a generation pool) participating in the aFRR market focussing on Germany and Austria [4]. However, based on the market situation in 2019, they found that BESS operation for aFRR provision was not economically feasible neither in the standalone mode, nor combined with a power generation plant. Their optimisation also considered battery deterioration cost, revenues from BESS arbitrage on the ID market as well as involved modelling of the aFRR bid acceptance probability. Furthermore, it was concluded that the estimated revenue from FCR provision would be higher than on the aFRR market [4].

1.2.2. BESS management for multi-market participation

Contrariwise, González-Garrido et al. studied battery storage operation aggregated with renewable generation focussing on portfolio profit maximisation in both wholesale (day-ahead (DA), ID) and reserve markets (FRR) based on the Spanish market data in 2017 [22]. They also considered battery aging and assessed optimal BESS sizing. It was concluded that participation in all the three mentioned markets with added storage increased the revenues, while also increasing the levelized cost of energy due to investment in the BESS. Consequently, the levelized cost per MWh was larger than the average annual revenue [22].

Generally, much fewer papers concern both frequency containment and frequency restoration or investigate the value-stacking options for BESS in more than one market. Namely, the keywords “stacked OR multi-market” yield only 19 papers[4] on BESS operational strategies focusing on multiple services or markets. E.g. Mohamed et al. [23] explored BESS participation in multiple markets, including wholesale (DA, ID) and ancillary services (FCR, FRR). Based on the French market data in 2021, they found that the largest income could be obtained from the reserve markets, especially aFRR. It was simulated that stacking different markets allowed increasing the revenue. For example, combining the DA and FCR market resulted in 76 % larger profit compared to employing two separate BESS for each service. However, this was not the case when stacking two reserve products such as the FCR with aFRR. The revenue maximisation was based on deterministic historical price data, hence considering the BESS operator a price taker and assuming their bids were always accepted [23].

Still, some studies explore the service stacking by selecting only one specific product type at once. For instance, Hammed et al. compared BESS participation in individual vs stacked[5] Nordic ancillary service markets [24] based on historical prices and frequency data in Denmark (DK2) assuming all submitted bids were accepted. However, for the stacked markets the BESS was considered to be participating in only one (most beneficial) market at each hour, and they did not address SOC restoration or any other cost [24]. In contrast, Rancilio et al. proposed such a multi-service strategy whereby the BESS would provide fast reserve (FR) for a part of the year while providing replacement reserve (RR) for the rest of it. This is because the FR service is requested only during 1000 h per year in Italy. They also considered bid acceptance

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[1] Scopus search results on 20/12/2023: TITLE-ABS-KEY (bess AND (fcr OR “frequency containment”)).

[2] Scopus search results on 20/12/2023: TITLE-ABS-KEY (bess AND (frr OR mfrr OR afrr OR “frequency restoration”)).

[3] Scopus search results on 19/12/2023: TITLE-ABS-KEY (battery AND frequency AND (strateg* OR algorithm*) AND market AND intraday).

[4] Scopus search results on 19/12/2023: TITLE-ABS-KEY (battery AND frequency AND (strategy OR algorithm) AND market AND (stack* OR multi-market)).

[5] Frequency-controlled normal operation reserve (FCR-N), frequency-controlled disturbance reserve (FCR-D) and fast frequency reserve (FFR).

based on historical prices of the Italian balancing market, and the RR bid price was determined so that the probability of bid acceptance in the required direction would be increased in line with the need for SOC restoration. This implies a passive SOC management for RR provision, whereas dead-band strategy was the only storage restoration approach considered for the FR, in line with the technical rules [25].

1.2.3. Main contributions

One of the main contributions and novelties of our paper is that we devise such an operational strategy of the BESS which allows simultaneous participation in both FCR and FRR (aFRR) markets and concurrent provision of both reserve types without any violations and subsequent penalties. We develop an active SOC management strategy via the ID market to ensure robustness and maximum availability (Section 2). The strategy considers if the BESS is qualified as a LER or not and is suitable for both cases, eventually allowing the user to compare their implications in the results. We test the performance of BESS with all the strategy variants under a hypothetical worst-case scenario to validate that it can indeed withstand extreme power system conditions and deliver all the reserves committed, and that this remains true also with varied market parameters such as the ID gate closure time (GCT) (Section 3). Afterwards, we model the performance of the strategy in more realistic operational scenarios (Section 4). These simulations of BESS operation involve historical frequency data from two different European synchronous areas (continental and Nordic) to obtain two distinctive scenarios. Moreover, we perform an economic assessment of the proposed operational strategy for two counterfactual scenarios based on the historical market prices in the German and Finnish markets to obtain a simplified cost-benefit analysis of the cashflows related to BESS operation in the FCR, aFRR and ID market (Section 5). Here, we combine the parameters of the planned BESS in Latvia and the expected Baltic balancing market design with real-world historical data from two other EU markets to obtain indicative economic results as there is no real-world data available from the yet non-existent Baltic balancing markets.[6] To the best of the authors' knowledge, no such analysis is available in the existing literature, especially considering the Baltic context and BESS value-stacking in different markets, fully compliant with the SOG and the recent CE TSOs' rules for FCR provision by a LER. Thus, our proposed management strategy respects all the regulatory requirements that a stand-alone frequency reserve providing BESS will be subjected to in the Baltic power system in the near future as well as in the EU in general. The strategy has been implemented in a mathematical simulation tool to validate its performance. Hence, the tool also allows testing the BESS operational strategy under various market settings (e.g. varied $\Delta T_{\mathrm{minLER}}$, ID GCT etc.) and storage parameters to validate the BESS ability to deliver the contracted services.

The remainder of the paper is organised as follows. Section 2 describes the devised BESS management algorithm and its implementation in the simulation tool. In Section 3, the robustness of the SOC control strategy is validated based on synthetic worst-case data. Section 4 describes the setup of realistic simulation case studies and their results, followed by economic assessment of the simulation results in Section 5 and conclusions in Section 6.

2. BESS Management strategy

2.1. Power system reserve types and markets

To clarify the rationale behind our BESS management strategy, we start with a short recap of the main regulations related to power system balancing focussing on the first two reserve types activated, FCR and aFRR (Fig. 1). To ensure system security, while achieving the necessary level of European harmonisation, SOG sets out common requirements for the EU electricity transmission system operation, e.g. harmonised rules for TSOs, their cross-border cooperation, provisions on load-frequency control and reserves, main operational principles of five synchronous areas etc. [7].

2.1.1. Characteristics of frequency containment and restoration reserves

According to SOG, frequency containment process aims to stabilise the system frequency after a disturbance within the steady-state range (50 ± 0.2 (Hz) in CE) by compensating imbalances with appropriate reserves (FCR) within a few seconds. To that end, there is a ± 0.01 Hz frequency response insensitivity or deadband in CE. Beyond this frequency deviation, a reserve provider should begin FCR provision immediately by automatically activating the agreed FCR proportionally to frequency deviation based on local frequency measurements. Namely, the active power output is decreased when the deviation increases in positive direction and vice versa. The full FCR capacity should be reached at ±0.2 Hz deviation at the latest after 30 s in CE. In general, there is no maximum duration for the FCR provision. The only exception is a provider with an energy reservoir limiting their FCR capacity [7]. Following FCR, the frequency restoration process steers the frequency towards its setpoint (50 Hz) by activating FRR within a few minutes and replacing FCR. There are two types of FRR depending on activation manner: manual and automatic, whereas the latter is activated based on control signals sent by the TSO to the aFRR provider [27]. The time to restore frequency is 15 min in CE [7]. Due to the fast response of BESS, in our study we focus on FCR and aFRR, although considerations similar to aFRR would be true also for mFRR as we assume an instant BESS response. After European harmonisation of the balancing market, the full activation time of aFRR is 5 min and that of mFRR – 12.5 min.

As concerns FCR provision by a LER, their alleviations according to SOG are valid only in case of a power system alert state. In CE synchronous area, an alert state is triggered when the absolute frequency deviation has continuously exceeded 0.05 Hz for 15 min or 0.10 Hz for 5 min [26].

2.1.2. Reserve types for frequency control in the Baltic states

As the Baltic states execute the unique synchronisation project, the TSOs need to implement a fundamentally new frequency control concept involving much larger amount of balancing reserves and requiring to establish new balancing markets in compliance with the EU regulations and CE synchronous area rules [17]. Other measures to ensure frequency stability and control of the Baltic power system include integration of synchronous compensators and implementation of several large-scale BESS projects, the size of which is remarkable even in the EU context. To procure reserves, the Baltic TSOs are going to employ both balancing capacity and energy markets starting from 2025 and involving several products, all of which have 15-min resolution, which equals one market time unit (MTU):

- FCR is a symmetric capacity-only product with bid submission closure time at 7:30 (EET) the day before delivery and procurement results published by 8:00 [28].
- For FRR, both capacity and energy can be procured with separate upward and downward regulation products. FRR capacity bids are submitted to the Baltic balancing capacity market by 9:00 the day before delivery and results published by 10:00 [28].
- For procurement and exchange of FRR energy, the Baltic TSOs are going to join the common European platforms: MARI for mFRR and PICASSO for aFRR. In case of a successful aFRR capacity bid acceptance, the aFRR provider is obliged to submit mandatory energy bids at the same volume. Additionally, voluntary aFRR energy bids may be submitted without a prior capacity offer. Balancing energy GCT is 25 min before each MTU [29].

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[6] At the time of writing, there is an mFRR market in the Baltics. Balancing markets for aFRR and FCR will be introduced in 2025.

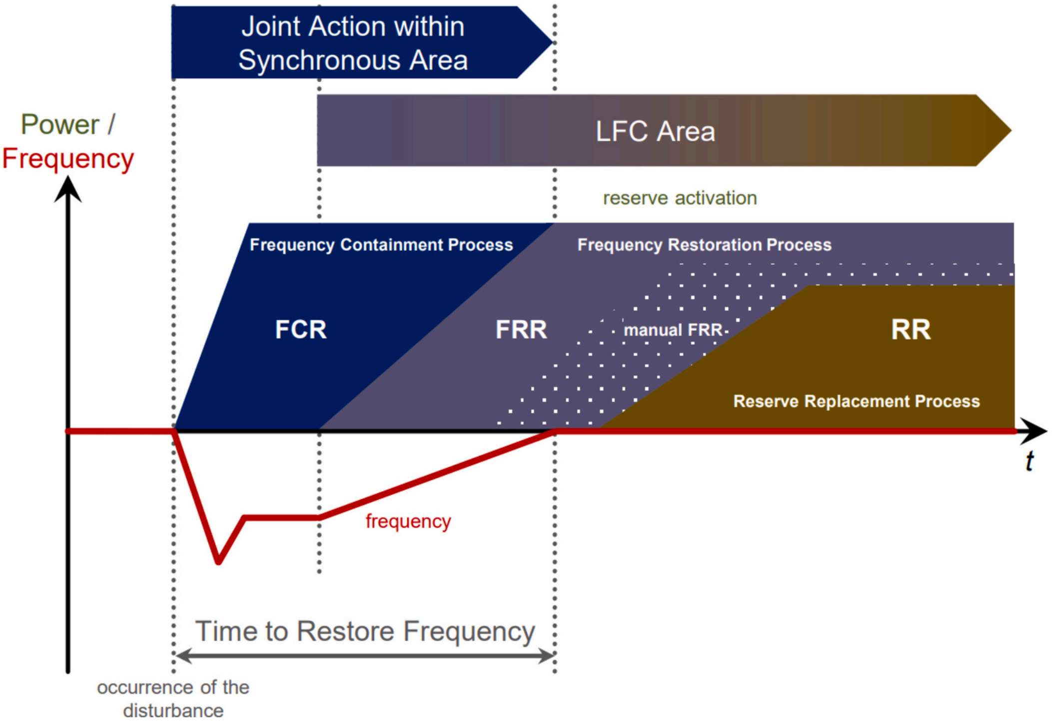

Fig. 1. Activation sequence of different power system reserve types for load-frequency control [26].

2.1.3. *TSO-owned BESS in Latvia*

Due to the risk of balancing reserve deficit and uncertainties brought by the Baltic power system synchronisation with CE, the TSOs have established several temporary measures to ensure secure system operation [17]. Among others, this includes utilisation of a large-scale BESS owned and operated by the Latvian TSO as a back-up resource in case of insufficient market liquidity. Our case study is focussed on the operational management strategy of this BESS with its planned technical parameters (80 MW/160 MWh). As the BESS is operated by the TSO, this has imposed several assumptions and constraints implemented within our simulation tool. One of the most important is energy restoration exclusively via the ID market and strict disallowance of any imbalance. While a BESS owned by a conventional producer might also be restored within their own portfolio, the requirement for ID market trades is a particularly strong constraint, especially considering the relatively long GCT of 60 min in the Baltics. However, this is in line with the recent EU regulations, particularly as concerns FCR provision by a LER, therefore our proposed approach and BESS management strategy devised would be applicable also in the EU in general, especially as the European balancing markets are harmonised. Restoration via the ID market would be relevant for new entrants in the FCR market without any existing generation portfolio, especially those who also need to comply with the $\Delta T_{\mathrm{minLER}}$ and other LER-specific requirements.

2.2. *Overall algorithm for BESS management strategy simulation*

The main purpose of our proposed BESS management strategy for participation in FCR and FRR markets with SOC restoration via ID market is to ensure robust ability of a reserve-providing BESS to fulfil its obligations in any circumstances following the regulatory requirements. The primary objective is to ensure sufficient SOC for guaranteed reserve activations, additional objectives being correct implementation of LER conditions (if applicable) and offering additional reserve volume in the balancing energy markets if such opportunities arise. It follows that this is an operational management strategy for reserve provision robustness and does not consider profit maximisation in the day-ahead timeframe. Namely, we consider the BESS to be sized for full FCR and aFRR provision according to the reserve requirements in Latvia dimensioned by the TSO. We consider the value-stacking in reserve markets while day-ahead wholesale trading remains an avenue for future work, whereby we could encompass the current operational strategy within a wider profit-maximising day-ahead optimisation model, for instance.

For the sake of clarity, we have separated the overall strategy in three main decision-making modules: (1) *BESS SOC management* (Section 2.3), (2) *LER management in alert state* (Section 2.4), and (3) *FRR voluntary energy bid estimation* (Section 2.5). In practical implementation, these modules would have to be integrated with the BESS control system and battery operator internal processes. However, in our simulation tool, these external connections are abstracted in order to validate the algorithm and management strategy in general, irrespective of any related control systems and business processes. A high-level overview of the simulation tool is provided in Fig. 2. The main purpose of the simulation tool setup is testing and validating the performance of our developed BESS management strategy detailed in the next subsections.

The simulations can be carried out for a variable time period with

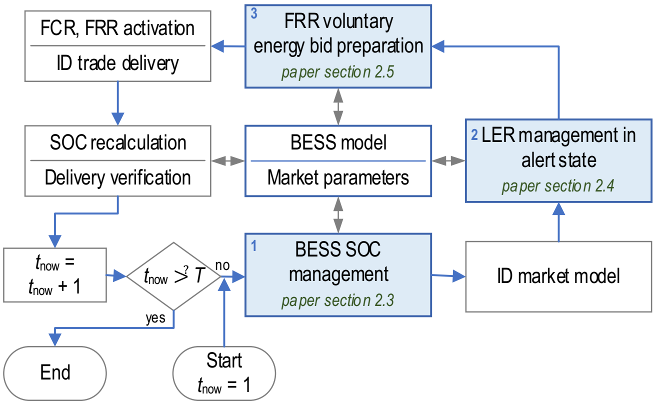

Fig. 2. Overall simulation flowchart for a reserve-providing BESS management with SOC restoration via the ID market.

adjustable temporal resolution, depending on the particular need, data available and computational considerations (e.g. too high resolution significantly increases the input/output data amount and the computational burden without necessarily improving the resulting calculation). Within each simulation timestep, the algorithm sequentially checks if any of the three decision-making modules (shaded process blocks in Fig. 2) needs to be activated. This activation depends on whether the pre-set decision-making time for the ID or FRR energy market bidding has arrived as well as on the current operational mode of the BESS (e.g. normal / reserve mode), recovery status etc. Each of these three principal parts of the BESS management strategy, including their activation conditions, is comprehensively described in the Sections 2.3–2.5.

The simulation tool also includes a stylised *ID market model*, which, activated after a BESS SOC management decision, can be used to simulate probabilistic BESS bid acceptance depending on the ID market liquidity. For instance, not all the ID trades required by the BESS might be realised. However, as this is not the focus of our study, in this paper we assume that ID trade proposals are always matched with a counterparty.

Furthermore, the *BESS model | Market parameters* block contains all the BESS technical parameters necessary to simulate its charge/discharge processes and the main technical parameters of the ID and reserve markets (e.g. GCT and other time-related settings for reserves and LER). Those input data are usually employed by a few processes at each simulation timestep, thus this block in Fig. 2 is interfaced with most of the other algorithm components.

After the decision-making modules have been executed (shaded process blocks in Fig. 2), in the *FCR, FRR activation | ID trade delivery* block the algorithm moves on to simulate the provision of FCR and FRR by the BESS and its priorly scheduled ID trades with a delivery due in the current MTU:

- the activated volume of FCR depends on the actual frequency (input data), the FCR capacity sold on the particular MTU (input data) and LER status;
- aFRR provision is subject to its control signals (input data in our study, but in practice sent to the BESS by the TSO) and the volume of mandatory and voluntary aFRR energy bids in place during the MTU.

The resulting balancing reserve activation and ID delivery data are then used to calculate the changes in the BESS SOC within this simulation timestep and estimate any non-delivery if SOC limits would have been violated. Finally, simulation moves on to the next timestep.

The three main modules of the BESS management strategy, which make up the crux of our approach, are explained in detail in the next subsections.

2.3. BESS state of charge management

The main goal of the BESS SOC management strategy is to prepare ID market bids for SOC restoration so that a sufficient BESS charge level is maintained for delivery of the contracted reserves during their validity period. To ensure full compliance with the SOG requirements and TSO rules, our devised strategy is based on a robust approach which consistently guarantees preparedness for the worst-case reserve activation scenario. The key steps of our SOC management strategy have been previously described in [30]. However, to provide a complete picture of the overall simulation algorithm, we also summarize the strategy here. The procedures in Section 2.3 generally concern both a LER and non-LER BESS management during both a normal and an alert state of the power system. However, following the recent EU regulation, there are additional LER-specific operational conditions and considerations that come into effect during an alert state only. Those are covered in Section 2.4.

The algorithm checks whether SOC restoration via the ID market is necessary whenever the current timestep t_{now} equals the ID decision-making time ($t_{\mathrm{ID,GCT,next}} - \Delta t_{\mathrm{prep}}$). In general, the time lag from the ID trade decision until its complete delivery can be >75 min in the Baltic market (GCT 60 min + delivery 15 min + a reliable user-set margin to prepare and execute the trade (5 min in our case study)). This is in contrast to, e.g. Germany, where the GCT of the ID continuous market can be as short as only 5 min[7] before the beginning of physical delivery [18]. With the 15-min delivery period, the total lag was therefore up to 20 min for the German case study in [18]. Generally, however, the specific lead time used in different studies has been subject to the relevant regulations at that time. For example, in earlier studies, the lead time considered for SOC restoration via the German ID market was up to 45 min in [5] and up to 60 min in [12]. On the other hand, the ID GCT was disregarded in a study focussed on the upcoming Baltic balancing market [21], even though the respective GCT is in fact 60 min in the Baltics [31].

To ensure robustness and compliance with varied market rules for research or business analysis purpose (in different geographies or in the future), the market time settings are adjustable in our algorithm. Interrelation between the different time-related variables for ID market trading is illustrated in Fig. 3 [30]. Once the ID market decision time, $t_{\mathrm{ID,decision}}$, is reached, the algorithm performs four main procedures detailed in Subsections 2.3.1–2.3.3.

2.3.1. Worst-case energy calculation

The most important step is to calculate the worst-case energy required from the reserve-providing BESS for power system up-regulation (i.e. BESS discharge) during the look-ahead horizon T_{LA}, which is the time period from the current t_{now} until the end of the ID delivery period under consideration, $t_{\mathrm{ID,end}}$,[8] where

$$t_{\mathrm{ID,end}} = t_{\mathrm{now}} + \Delta t_{\mathrm{prep}} + \Delta t_{\mathrm{ID,GCT}} + \Delta t_{MTU}. \tag{1}$$

Generally, the worst-case energy comprises the sum of fully activated FCR and FRR up-regulation reserves (according to the sold capacity), full delivery of priorly scheduled ID trades[9] and energy losses due to self-discharge. For a conventional (non-LER) FCR provider, which is bound to provide FCR continuously during long-lasting frequency deviations, this worst-case energy estimation equals:

$$E_{\mathrm{worst,UP}} = \sum_{t \in T_{\mathrm{LA}}} \Big(\big(P_{\mathrm{FCR}}(t) + P_{\mathrm{FRR,UP,mand}}(t) + P_{\mathrm{FRR,UP,vol}}(t) + P_{\mathrm{ID}}(t) \big) \cdot \Delta t / (1\ \mathrm{h}) + \Delta E_{\mathrm{s.d.}}(t) \Big). \tag{2}$$

Instead, a LER does not have to guarantee full FCR[10] activation for the whole look-ahead horizon [8]. Namely, in worst-case scenarios, as shown in Fig. 4, a LER is required to ensure nearly 50 % FCR activation for 10 min + nearly 100 % activation for 5 min (after which a power system alert state is triggered) + 100 % activation for $\Delta T_{\mathrm{minLER}}$ (30 min[11]) during the alert state in line with LER requirements and alleviations [5]. After fulfilling the $\Delta T_{\mathrm{minLER}}$ requirement, the LER could stop proportional FCR provision (or enter reserve mode). However, in a worst-case setting, the power system *normal* state is restored right after the $\Delta T_{\mathrm{minLER}}$ criterion completion, and there are no more alleviations for

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[7] If within the same control area.

[8] In other words, it is a set T_{LA} such that $T_{\mathrm{LA}} = \{t_{\mathrm{ID,decision}}, t_{\mathrm{ID,decision}} + \Delta t, \ldots, t_{\mathrm{ID,end}}\}$.

[9] The variable $P_{\mathrm{ID}}(t)$ assumes a positive value for an ID market sell trade and a negative value for a buy trade.

[10] It should be noted that there are no special conditions in SOG for LERs concerning FRR delivery. Thus, in contrast to FCR, the BESS should be able to provide the contracted FRR volume at all times irrespective of the power system state.

[11] While we use a 30 min $\Delta T_{\mathrm{minLER}}$ in our case studies, the criterion can be 15–30 min in CE as mentioned in Section 1.

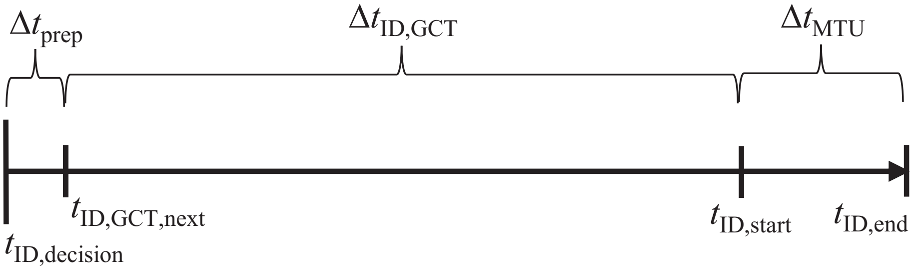

Fig. 3. Interrelation of the time-related ID market variables.

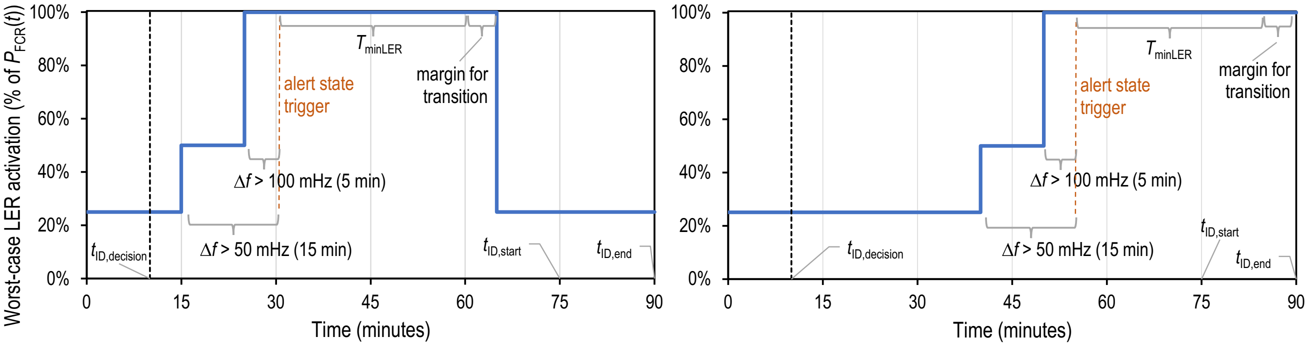

Fig. 4. FCR worst-case activation examples for a LER, illustrating the alert state trigger, ΔT_{minLER} criterion and a safety margin for transition to reserve mode.

the LER since they are valid only during the system *alert* state. Therefore, the BESS again needs to provide FCR activation proportional to the frequency deviation. Note that immediately after an alert state, we assume ≤25 % continuous FCR activation (within the standard frequency range) as otherwise the alert state would not have been ended. Such a chain of events can have pronounced impact in case of sufficiently long ID market lead times as is true for the Baltic states, for instance. Furthermore, in contrast to [5], we add another 5 min of full FCR activation for the worst-case energy estimation to safely handle LER's transition from normal to reserve mode (explained in more detail in Section 2.4).

If the contracted FCR capacity varies across different MTUs within the look-ahead horizon, there are many different trajectories how the worst-case scenario could play out which significantly complicates calculating the energy requirements. Therefore, to obtain a robust worst-case energy estimation for an FCR-providing LER, a combinatorial problem needs to be solved [30]. We refer to the example of two different FCR worst-case activation scenarios shown in Fig. 4. Here, the *y*-axis shows the activation of FCR as a percentage of the committed (sold) $P_{\text{FCR}}(t)$ by the reserve provider. The volume of reserves activated is proportional to the frequency deviation. While both charts in Fig. 4 reflect a supposedly similar worst-case activation scenario, the deviation is shifted in time. This in turn can lead to significant differences if the committed reserve capacity varies in time as explained below.

Both scenarios begin with a normal state of the power system. Then, in minute 30 (left chart) or minute 50 (right chart) a power system alert state is triggered after suffering a deviation of >50 mHz for 15 min. Note that the alert state would be also triggered solely by the illustrated deviation of >100 mHz for 5 min, but in the *worst-case* estimation, we sequentially combine both deviations as they increase the energy need.

Since the contracted reserve capacity $P_{\text{FCR}}(t)$ per MTU can vary during the analysed 90-min (6-MTU) horizon, the sum of the worst-case FCR energy depends on the sold capacity with respect to the frequency deviation trajectory. To illustrate this effect, let us assume that in Fig. 4 for both examples the contracted $P_{\text{FCR}}(t)$ is 0 MW during the first three MTUs (minute 0…44) and 10 MW during the last three MTUs (minute 45…90). Then, relating this volume to the frequency deviation, we can calculate the energy requirements. In our examples, the respective LER worst-case energy for FCR yields ~4.6 MWh for the left chart scenario and ~7.1 MWh for the right chart's frequency deviation trajectory. Alternatively, if the contracted $P_{\text{FCR}}(t)$ was equal and uniform during the whole 90-min horizon in both examples, then the required energy would be equal.

Consequently, to estimate the worst-case FCR energy for a LER as opposed to a non-LER, we replace the energy amount corresponding to $P_{\text{FCR}}(t)$ in (2) with $E_{\text{LER,FCR,UP}}$ which selects that FCR activation scenario which yields the highest energy requirement according to the combinatorial problem solved by (4):

$$E_{\text{worst,UP}} = \sum_{t\in T_{\text{LA}}} \Big(\big(P_{\text{FRR,UP,man}}(t) + P_{\text{FRR,UP,vol}}(t) + P_{\text{ID}}(t) \big) \cdot \Delta t / (1\ \text{h}) + \Delta E_{\text{s.d.}}(t) \Big) + E_{\text{LER,FCR,UP}}, \tag{3}$$

where

$$E_{\text{LER,FCR,UP}} = \max_{s\in S} \left(\sum_{t\in T_{\text{l.a.}}} \left(P_{\text{FCR}}(t) \cdot \Delta f_s(t) / \Delta f_{\max} \right) \right) \cdot \Delta t \Big/ (1\ \text{h}). \tag{4}$$

If the FCR capacity does not vary during the look-ahead horizon, it is sufficient to compute just one of the alternatives s from the scenario set S in (4) as they all yield the same energy amount.

Similarly to the up-regulation, we also estimate the worst-case down-regulation energy. The only difference is that the self-discharge losses ($\Delta E_{\text{s.d}}$) are not considered as they do not worsen the situation in a worst-case down-regulation scenario.

Based on the worst-case energy needs estimated for both FCR directions, the ID market trade can be scheduled, which will also be different for LER and non-LER FCR providers. Although we could, of course, use the robust non-LER energy estimation also for a LER, this would lead to more active corrective actions for SOC management, potentially useless ID trades and increased operational cost, hence not benefitting from the LER's alleviations. Hereinafter, we refer to the algorithm which considers the easier requirements of a LER as the Conservative strategy and the algorithm for a non-LER as the Active strategy to reflect the most distinctive features of both approaches.

2.3.2. Energy sufficiency check

Once the worst-case energy has been estimated, we move on to calculate the energy available in the BESS for up- and down-regulation, respectively, which depends on the current energy content in the reservoir, its storage capacity and charge/discharge efficiency:

$$E_{\mathrm{av.UP}} = (SOC - SOC_{\min})\cdot\eta_{\mathrm{disch}}, \tag{5}$$

$$E_{\mathrm{av.DOWN}} = (SOC - SOC_{\max})/\eta_{\mathrm{ch}}. \tag{6}$$

Afterwards, we check if the worst-case up-regulation energy exceeds the available one: $E_{\mathrm{worst,UP}} \overset{?}{>} E_{\mathrm{av.UP}}$. If so, an ID buy bid is prepared for BESS charging (detailed in the next step). Otherwise, we check if there is insufficient energy in the opposite direction (for down-regulation): $E_{\mathrm{worst,DOWN}} \overset{?}{>} E_{\mathrm{av.DOWN}}$ and, if true, prepare an ID sell bid for BESS discharge.

2.3.3. ID bid preparation

We start the ID buy bid preparation by calculating the available BESS power for the respective ID delivery period (T_{ID}), which depends on the total BESS power and the contracted FCR and aFRR down-regulation capacity[12]:

$$P_{\mathrm{ch.av.}}(T_{\mathrm{ID}}) = -\left(P_{\mathrm{ch.}max} - P_{\mathrm{FCR}}(T_{\mathrm{ID}}) - P_{\mathrm{FRR,DOWN,mand}}(T_{\mathrm{ID}}) - P_{\mathrm{FRR,DOWN,vol}}(T_{\mathrm{ID}})\right). \tag{7}$$

Then, we calculate the power corresponding to the delivery of the required energy within T_{ID}. As we generally assume that the positive power flow direction is from the BESS to the grid, the ID market buy bid or BESS charging power assumes a negative value. Thus, we obtain the ID buy bid by selecting the maximum between two values:

$$P_{\mathrm{ID}}(T_{\mathrm{ID}}) = max\left(P_{\mathrm{ch.av.}}(T_{\mathrm{ID}}),\ -\left(E_{\mathrm{worst,UP}} - E_{\mathrm{av.UP}}\right)\cdot(1\ \mathrm{h})/\Delta t_{\mathrm{MTU}}\right). \tag{8}$$

A similar process is followed with ID sell bids for BESS discharge. Here, the power assumes a positive value, therefore we select the minimum between two values as follows:

$$P_{\mathrm{disch.av.}}(T_{\mathrm{ID}}) = P_{\mathrm{disch.}max} - P_{\mathrm{FCR}}(T_{\mathrm{ID}}) - P_{\mathrm{FRR,UP,mand}}(T_{\mathrm{ID}}) - P_{\mathrm{FRR,UP,vol}}(T_{\mathrm{ID}}), \tag{9}$$

$$P_{\mathrm{ID}}(T_{\mathrm{ID}}) = min\left(P_{\mathrm{disch.av.}}(T_{\mathrm{ID}}),\ \left(E_{\mathrm{worst,DOWN}} - E_{\mathrm{av.DOWN}}\right)\cdot(1\ \mathrm{h})/\Delta t_{\mathrm{MTU}}\right). \tag{10}$$

If the BESS power available for trading in the ID market according to (8) and (10) turns out insufficient with respect to the energy needed for SOC restoration, it means either the reserves to be provided by the BESS have been oversized or a worst-case scenario has already begun. In the first case, the infeasible outcome of the simulation allows the user to reconsider the reserve provision or BESS parameters, which is also one of the use cases for our simulation tool as it enables to simulate in detail the BESS operation to verify different technical parameters under various real-life or worst-case frequency deviation scenarios. In the latter case, during an already ongoing worst-case scenario, this is not necessarily a concern for the BESS operator since the LER conditions give them ample time to recover post alert state. Either way, a warning is issued to the user in case of an insufficient BESS power.

2.4. Management of LER-specific conditions during alert state

While the previous Section 2.3 concerned the management of both a LER and non-LER BESS during normal and alert state, we also need to implement LER-specific conditions during the alert state in accordance with the recent EU regulation. This is the objective of module described in this Section 2.4, which deals with LER management during and after power system alert state implementing the reserve mode of an FCR-providing LER and transition to it from normal mode in compliance with TSO requirements which allow specific alleviations for a LER during long-lasting alert state [8,26]. Thus, the module also tracks the fulfilment of the $\Delta T_{\mathrm{minLER}}$ criterion and the completion of LER's SOC recovery post alert state.

As already mentioned, a LER is required to provide a continuous FCR activation during power system normal state. This operation can also be referred to as LER **'normal mode'**. Instead, for operation during a prolonged alert state, a specific LER **'reserve mode'** has been introduced [8]. It implies that during long-lasting frequency deviations, after the LER has provided full FCR capacity for a duration of at least $\Delta T_{\mathrm{minLER}}$ during alert state, it should switch to respond only to short-term deviations in case the reservoir is close to exhaustion. The short-term frequency deviation is calculated real-time as the difference between the average frequency deviation during the last 5 min and the instantaneous deviation. Thus, the reservoir depletion is slowed down, and the LER is said to operate in 'reserve mode'. Consequently, the power system can longer benefit from the LER even during a power system alert state, while the LER continues to provide less FCR as the reservoir approaches exhaustion [8].

In addition, it is required that the LER enters or exits its reserve mode by gradually adjusting their FCR provision to avoid sharp fluctuations. This so-called **'transition'** duration is equal to the full activation time of aFRR (5 min) so that aFRR providers can smoothly take over the regulation provided by the (almost) depleted LER FCR asset (and vice versa). During this mode, the LER transitions from normal to reserve mode step by step: it linearly reduces its response to the actual frequency deviation from 100 % to 0 % while at the same time increasing its reaction to the short-term frequency deviation from 0 % to 100 % (or vice versa). Thus, an FCR-providing LER is always operating in one of the three modes: normal mode, reserve mode or transition.

The technical intricacies of the LER reserve mode and transition have not been fully defined yet by all CE TSOs. However, the existing regulation allows us to make several assertions required for the rule-based management of the LER during and right after system alert state [8]. For instance, we track the fulfilment of $\Delta T_{\mathrm{minLER}}$ criterion based on the equivalent FCR energy provided by the LER (instead of FCR activation duration). Namely, the criterion is met once the energy delivered by the BESS since the beginning of system alert state amounts to 100 % of FCR activation for a duration of $\Delta T_{\mathrm{minLER}}$.

According to SOG, a LER FCR provider should "ensure the recovery of the energy reservoirs as soon as possible, within 2 hours after the end of the alert state" [7]. During this 'recovery time' the LER should restore its SOC to such a level that it is once again ready for a prolonged FCR activation in a new potential alert state. Within our robust SOC management strategy, this recovery takes place irrespective of the three LER modes mentioned above. To always ensure BESS resilience in worst-case scenarios, our algorithm implements a relatively proactive SOC management at all times. It means there are no extraordinary considerations for SOC restoration and ID market trade scheduling if the LER is in the recovery phase. For the purposes of our LER management module, recovery status only implies that we continuously track if the SOC is restored to a sufficient level so that, considering also the priorly scheduled ID trades, the LER can ensure full FCR provision during a potentially upcoming worst-case scenario. Thus, the recovery status implies that the LER cannot guarantee a new fulfilment of the $\Delta T_{\mathrm{minLER}}$ criterion following an exhaustive worst-case assessment (explained in more detail below). It follows that, during recovery, LER still fully participates in FCR provision during normal state with its normal mode, whereas LER is activated only in reserve mode during alert state.

Still, there remains some uncertainty in the interpretation of SOG and TSO rules concerning requirements for LER FCR providers. A LER should have an active energy reservoir management strategy implemented [8], which is verified by the TSO during prequalification [26] but still allows some freedom of choice in some aspects. To that end, we

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[12] Here and elsewhere, T_{ID} is a set such that $T_{\mathrm{ID}} = \{t_{\mathrm{ID,start}}, t_{\mathrm{ID,start}} + \Delta t, \ldots, t_{\mathrm{ID,end}}\}$.

Table 1

Logical flags implemented for managing LER reserve mode and recovery status during/after power system alert state.

(1)[a]	(2)[a]	(3)[a]	Preconditions	Actions
1	1	1	A new alert state has started while LER is in recovery from a previous one, thus LER immediately switches to reserve mode.	At each timestep, check if it is possible (or mandatory) to exit recovery. If it is, declare recovery over and begin transition to normal mode.
1	1	0	Impossible combination since, if LER is in recovery during alert state, it must be operating in reserve mode.	n/a
1	0	1	Alert state has ended, while LER is in transition to normal mode or cancelling transition to reserve mode.	Check if it is possible (or mandatory) to exit recovery. If it is, declare recovery over.
1	0	0	Full FCR provision during normal state (but immediate switching to reserve mode if an alert state starts).	Check if it is possible (or mandatory) to exit recovery. If it is, declare recovery over.
0	1	1	Possible (a) if ΔT_{minLER} criterion is fulfilled during the current alert state or (b) if we declare exit from recovery during an alert state due to exceeding time limit.	(a) If LER is not in transition, check if it can exit reserve mode. If so, begin transition to normal mode. (b) LER must begin transition to normal mode, even though it cannot guarantee fulfilment of ΔT_{minLER}.
0	1	0	Normal mode during alert state.	Track the fulfilment of the ΔT_{minLER} criterion. If the criterion is fulfilled, check if it is necessary to enter reserve mode. If so, begin transition to reserve mode.
0	0	1	Only possible after the end of alert state, while LER is in transition to normal mode or cancelling a transition to reserve mode, if at the end of the alert state it was established that LER does not need to enter recovery.	Continue the transition or cancelling of transition.
0	0	0	Normal operation within the normal state.	LER is expected to be ready to fulfil the ΔT_{minLER} criterion if an alert state starts. However, if a prior recovery was declared over prematurely due to exceeding its time limit, it is possible that fulfilling the criterion could fail under select circumstances.

[a] (1) LER in recovery? (2) Power system alert state? (3) LER reserve mode / transition?

have incorporated a number of informed assumptions within our algorithm module managing LER reserve mode and post alert state recovery. A key assertion is that entering/exiting the reserve mode depends on the LER's ability to withstand a new fulfilment of the ΔT_{minLER} criterion based on an exhaustive worst-case assessment. However, if the LER returns to normal mode during the same alert state in which the criterion has already been fulfilled, it will not transition to reserve mode again unless the ΔT_{minLER} criterion is fulfilled anew. This is to maximise the reserves obtainable from a LER while also minimising the switching to and from reserve mode. However, if a LER is in reserve mode when the alert state ends, it begins transitioning to the normal mode at once. An additional assumption implemented within our BESS management strategy is that if LER is in recovery when a new alert state starts, it enters reserve mode immediately (without transition).

Based on the assertions described above, we have implemented the algorithm module dealing with LER management in alert state based on three main logical flags which determine the BESS operation as concerns LER reserve mode and recovery status, covering all the possible combinations. The preconditions and actions for each combination of these flags are summarised in Table 1.

2.4.1. *Exhaustive worst-case evaluation*

The algorithm decides whether the LER should exit/enter reserve mode or assume recovery status based on exhaustive worst-case evaluation, unless an ongoing recovery needs to be ended due to the time limit. This worst-case consideration is similar to the SOC management strategy for ID trades (Section 2.3.1). The key difference is that in this case we have to assume that the BESS SOC constraints might be violated not just at the end of the look-ahead horizon (last Δt_{MTU}, which is the ID trade window under consideration in Section 2.3.1), but at any point during the whole horizon. This can happen due to prolonged or subsequent alert states etc. For the exhaustive assessment, we repeat the worst-case energy calculation for a varied look-ahead horizon by iteratively reducing the horizon t^* until the worst-case reserve provision cannot be ensured by the LER due to insufficient available energy. If at no point this is the case, then the reserve mode (or recovery status) is not needed.

The exhaustive worst-case assessment described above can best be explained with the following pseudocode:

```
FOR index $t^* = t_{\text{now}} + \Delta t_{\text{LA}}$ TO $t_{\text{now}}$ STEP $- \Delta t$
  IF (10) OR (11)
      register the exhaustive worst-case resilience test as failed
      EXIT LOOP
    ENDIF
ENDFOR
```

Within this assessment, we use the conditions (11) and (12) for the exhaustive worst-case resilience test to check if the available energy in each direction is sufficient to withstand a worst-case scenario. In accordance with the pseudocode above, the conditions are checked numerous times, varying the upper bound (t^*) of the summation operator on the right-hand side to reduce the calculation horizon step-by-step:

$$E_{\text{av.UP}} \geq \sum_{t=t_{\text{now}}}^{t^*} \left(\left(P_{\text{FRR,UP,mand}}(t) + P_{\text{FRR,UP,vol}}(t) + P_{\text{ID}}(t) \right) \cdot \Delta t / (1\ \text{h}) + \Delta E_{\text{s.d.}}(t) \right) + E_{\text{LER,FCR,UP}}, \tag{11}$$

$$E_{\text{av.DOWN}} \geq \sum_{t=t_{\text{now}}}^{t^*} \left(\left(P_{\text{FRR,DOWN,mand}}(t) + P_{\text{FRR,DOWN,vol}}(t) - P_{\text{ID}}(t) \right) \cdot \Delta t / (1\ \text{h}) \right) + E_{\text{LER,FCR,DOWN}}. \tag{12}$$

In a generalised case, the LER FCR worst-case energy,[13] calculated in Eq. (13), can depend on its realisation scenarios as already described in Subsection 2.3.1 for Eq. (4). Since Eq. (13) feeds into the conditions (11) and (12), it uses the same values for t^* as in (11)–(12):

$$E_{\text{LER,FCR,UP}} = E_{\text{LER,FCR,DOWN}} = \max_{s \in S} \left(\sum_{t=t_{\text{now}}}^{t^*} \left(P_{\text{FCR,}}(t) \cdot \Delta f_s(t) / \Delta f_{\max} \right) \right) \cdot \Delta t \Big/ (1\ \text{h}). \tag{13}$$

In accordance with Table 1, the priorly explained exhaustive worst-case assessment procedure is performed based on the following provisions: whenever the LER is in recovery and the recovery time limit is not exhausted, we check if it can be exit; whenever the LER is in reserve

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[13] Since FCR is a symmetrical product, the worst-case LER FCR energy is equal for both regulation directions.

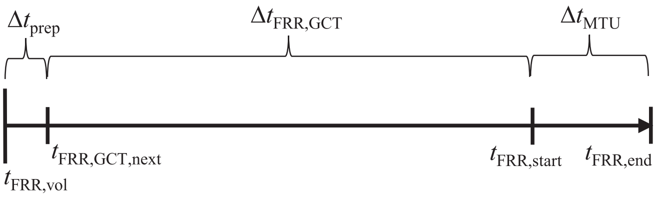

Fig. 5. Interrelations of the time-related variables concerning voluntary FRR energy bidding.

mode, we check if it can switch to normal mode; whenever the power system is in alert state after the LER has already fulfilled the $\Delta T_{\mathrm{minLER}}$ criterion, we check if it needs to switch to reserve mode; whenever the alert state ends, we check if the LER needs to enter recovery.

2.4.2. LER recovery time

While SOG allows a LER to enjoy a maximum of 2-hour recovery time after alert state, due to practical considerations from the system operator point of view, we consider that a faster recovery is preferable if the alert state has been comparatively short. We assume that the maximum time allotted for LER recovery is proportional to the FCR energy that the LER has provided during the alert state. In our simulation tool, this fulfilment is continuously tracked by calculating a ratio of the LER's actual contribution to the full FCR activation equivalent:

$$k_{\mathrm{FCR}}(t_{\mathrm{now}}) = k_{\mathrm{FCR}}(t_{\mathrm{now}} - \Delta t) + \frac{\Delta t \cdot min\left(\Delta f_{\mathrm{f.a.}}, |\Delta f(t_{\mathrm{now}})|\right)}{\Delta T_{\mathrm{minLER}} \cdot \Delta f_{\mathrm{max}}} \cdot 100\%. \tag{14}$$

Thus, when an alert state ends, the maximum time for LER's recovery is equal to

$$\Delta t_{max.\mathrm{rec.}} = min(\Delta T_{max.\mathrm{rec.}}, k_{\mathrm{FCR}}(t_{\mathrm{now}}) \cdot \Delta T_{max.\mathrm{rec.}}). \tag{15}$$

Note that ratio k_{FCR} tracking the $\Delta T_{\mathrm{minLER}}$ criterion is reset whenever an alert state ends or whenever LER exists reserve mode during an ongoing alert state.

2.5. FRR voluntary energy bid preparation

The main purpose of the module for voluntary FRR energy bidding is to prepare the bids that the BESS can offer to the market taking into account its parameters and SOC. Since FCR and FRR capacity market bids are submitted once a day, they are not dependent on the current SOC but rather only on the BESS parameters and the reserve needs. Similarly to the BESS parameters, the volume of reserves required from the BESS is a fixed or time-varying user-set parameter in our simulation tool, but in practice it would depend on the TSO's dimensioned demand for reserves and the capacity market outcome. When an FRR capacity bid is accepted, the BESS then needs to submit a respective mandatory energy bid. In order to further extend the usage of our BESS, we implement also voluntary energy bidding for FRR within our algorithm if this turns out feasible during the course of the day (GCT for FRR energy bids in the Baltic market is 25 min). To enable the BESS to submit voluntary FRR energy bids, we have implemented a more sophisticated procedure compared to the capacity and mandatory energy bidding, which accounts for the actual trajectory of the SOC as well as other reserve obligations and priorly made ID trades.

The main principle of the voluntary FRR energy bidding strategy is to use only the available capacity (power- and energy-wise), left after successfully handling a hypothetical worst-case activation scenario. This means that our algorithm would not consider making proactive ID market trades with the purpose of increasing the available capacity for FRR energy bidding in a specific direction. However, if ID trades have been made for SOC management and turn out not to be critical for maintaining the SOC (because the worst-case scenario did not materialise), then such prior ID trades can at times increase the capacity available for voluntary FRR energy bids.

The module for voluntary FRR bid preparation operates as described in Subsections 2.5.1–2.5.4. The process starts at FRR energy market bid decision time $t_{\mathrm{FRR,vol}}$. The time-related variables are visually explained in Fig. 5.

2.5.1. Available power calculation

We start by calculating the discharging and charging power available for voluntary FRR energy bids[14] for the upcoming MTU by subtracting the previously committed FCR, FRR capacity and ID market trades from the total BESS power in each direction:

$$P_{\mathrm{disch.av.}}(T_{\mathrm{FRR}}) = P_{\mathrm{disch.}max} - P_{\mathrm{FCR}}(T_{\mathrm{FRR}}) - P_{\mathrm{FRR,UP,mand}}(T_{\mathrm{FRR}}) - P_{\mathrm{ID}}, \tag{16}$$

$$P_{\mathrm{ch.av.}}(T_{\mathrm{FRR}}) = P_{\mathrm{ch.}max} - P_{\mathrm{FCR}}(T_{\mathrm{FRR}}) - P_{\mathrm{FRR,DOWN,mand}}(T_{\mathrm{FRR}}) + P_{\mathrm{ID}}, \tag{17}$$

If (16) or (17) yields larger than 0, it means there is discharging or charging power available, so we calculate the respective up- and down-regulation energy available in the BESS at the current timestep t_{now} using Eqs. (5)–(6).

2.5.2. Worst-case energy calculation

Next, we calculate the worst-case up- and down-regulation energy that the BESS needs to be able to ensure from the current timestep t_{now} until the end of the considered FRR energy bid validity period $t_{\mathrm{FRR,end}}$ based on Eqs. (2) or (3), subject to LER status. Thus, the approach is the same as in Section 2.3, except that the look-ahead horizon, T_{LA}[15], has been adapted to the FRR market timeframe and the end timestep is as follows:

$$t_{\mathrm{FRR,end}} = t_{\mathrm{now}} + \Delta t_{\mathrm{prep}} + \Delta t_{\mathrm{FRR,GCT}} + \Delta t_{MTU}. \tag{18}$$

2.5.3. Preliminary FRR energy bid

We check if the energy available in the BESS for up- or down-regulation exceeds the worst-case energy requirement in the respective direction. If so, we prepare preliminary FRR energy bids in this direction. For the voluntary up-regulation FRR energy bid:

$$P^{*}_{\mathrm{FRR,UP,vol}}(T_{\mathrm{FRR}}) = max\Big(0, min\big(P_{\mathrm{disch.av.}}(T_{\mathrm{FRR}}), (E_{\mathrm{av.UP}} - E_{\mathrm{worst,UP}}) \cdot (1\ \mathrm{h}) / \Delta t_{\mathrm{MTU}}\big)\Big). \tag{19}$$

For the down-regulation bid:

$$P^{*}_{\mathrm{FRR,DOWN,vol}}(T_{\mathrm{FRR}}) = max\Big(0, min\big(P_{\mathrm{ch.av.}}(T_{\mathrm{FRR}}), (E_{\mathrm{av.DOWN}} - E_{\mathrm{worst,DOWN}}) \cdot (1\ \mathrm{h}) / \Delta t_{\mathrm{MTU}}\big)\Big). \tag{20}$$

2.5.4. FRR energy bid finalisation

Once the potential bids have been estimated, we start a SOC violation subroutine. Its main purpose is to check if a voluntary FRR energy bid estimated for a particular MTU causes issues in other time periods, and if it does, reduce it to an extent where no issues are expected. The subroutine consists of two nested loops, as can be seen in the pseudocode below. The outer ("while") loop varies the preliminarily estimated FRR energy bid, whereas the inner ("for") loop performs the exhaustive worst-case enumeration in the same manner as in Section 2.4.1. If the inner loop finds a violation, the outer loop reduces the preliminary bid by one unit (1 MW in the Baltic market).[16] The process continues until the inner loop finds no violations in any of its iterations with the current preliminary bid volume. If so, that bid is considered as the final and safely submittable voluntary FRR energy bid. On the other hand, if in the outer loop the preliminary bid is reduced less than the minimum bid size

---

[14] Here and elsewhere, T_{FRR} is a set such that $T_{\mathrm{FRR}} = \{t_{\mathrm{FRR,start}}, t_{\mathrm{FRR,start}} + \Delta t, \ldots, t_{\mathrm{FRR,end}}\}$.

[15] In this section, T_{LA} is a set such that $T_{\mathrm{LA}} = \{t_{\mathrm{FRR,vol}}, t_{\mathrm{FRR,vol}} + \Delta t, \ldots, t_{\mathrm{FRR,end}}\}$.

[16] In accordance with the aFRR energy bid granularity defined by the TSO.

(due to failing the inner loop check with all the values), a voluntary bid is not to be made. This process is implemented with the following pseudocode.

```
WHILE $P^{*}_{\mathrm{FRR,UP,vol}}(T_{\mathrm{FRR}}) \geq$ minimum FRR energy bid volume
    FOR index $t^{*} = t_{\mathrm{now}} + \Delta t_{\mathrm{LA}}$ TO $t_{\mathrm{now}}$ STEP–$\Delta t$
        IF (10) OR (11)
            register the exhaustive worst-case estimation test as failed
            reduce the value of $P^{*}_{\mathrm{FRR,UP,vol}}(T_{\mathrm{FRR}})$ by 1 unit
            EXIT FOR LOOP
        ENDIF
    ENDFOR
IF $P^{*}_{\mathrm{FRR,UP,vol}}(T_{\mathrm{FRR}}) <$ minimum FRR energy bid volume
    a voluntary FRR energy bid is not made
ELSE
    submit a voluntary FRR energy bid with volume $P^{*}_{\mathrm{FRR,UP,vol}}(T_{\mathrm{FRR}})$
ENDIF
```

It is valuable to note that the FRR voluntary energy bid preparation algorithm can be repurposed also to use the 'surplus' BESS energy not needed for FCR and FRR capacity obligation fulfilment to prepare additional ID bids with a profit-increasing objective. This option has not been incorporated in the current study as it was out of scope for the specific paper due to the case study setup, where the BESS is operated by the TSO, and instead is considered for future work.

3. Validation of the SOC management strategy

To verify the robustness of our devised algorithm and its three main modules detailed in Sections 2.3–2.5, we thoroughly test it by simulating the operation of a reserve-providing BESS in a hypothetical extreme scenario. Moreover, we compare how the selection of SOC management strategy (conservative or active) impacts the operation as well as the rigorousness of the management approaches under varied market settings, particularly, different ID GCTs. This allows analysing implications of different regulations considering that the market time settings can still be quite varied across different EU countries and thus can impact the BESS management and business in general.

We assume a BESS with the following technical parameters[17]: rated active power of 80 MW, rated energy capacity of 160 MWh, round-trip efficiency of 0.9025, self-discharge losses of 0.08 % per day, min/max SOC limit 10 % and 90 %, and initial SOC equal to 50 %. The expected market demand for reserves is set to 8 MW for the symmetrical FCR and 32 MW for FRR capacity in both directions, which is similar to the estimated FCR and aFRR needs in Latvia based on the TSO dimensioning results [27]. For validation purposes, we simulate the BESS providing a uniform (maximum) reserve capacity. This implies the modelled BESS ensures all the FCR and aFRR needs of the country. In principle, the simulation tool would allow also to test time-varying reserve capacity with a different volume per each 15-min MTU. This would be crucial if we simulated multiple parties providing the reserve needs, thus we leave it for future work.

Market parameters are based on the Baltic case with a 25 min GCT for the aFRR energy market and a 60 min GCT for the ID market, whereas the capacity bids are exogenously assumed to equal the market demand (in practice, they are submitted the day before, see Section 2.1). The user-set decision time for bid submission is 5 min. The power system frequency deviation for full FCR activation is ±0.2 Hz with a deadband of ±0.01 Hz as in CE synchronous area. The minimum duration of full FCR activation by a LER, $\Delta T_{\mathrm{minLER}}$, is set to 30 min [26].

We simulate a total of 6 h of BESS operation with 1 min resolution and test both the Conservative and Active BESS SOC management strategies. As described in Section 2.3, the Conservative strategy is suited only for a LER FCR provider and considers their alleviations during system alert state when preparing corrective ID trades, while the Active strategy is applicable to non-LER assets (i.e. conventional FCR providers) and requires continuous BESS availability irrespective of the system state. The extreme scenario we simulate is characterised by continuous full aFRR demand provided by the BESS and a constant frequency deviation of +0.2 Hz, thus requiring full unidirectional FCR activation of a LER for a duration of at least $\Delta T_{\mathrm{minLER}}$ and a continuous full FCR activation for a non-LER BESS. For validation purposes, we have assumed a unidirectional frequency deviation. In addition to the constant FCR demand, we assume a full activation of aFRR in the same direction to simulate the harshest possible operational conditions for the BESS, preventing any 'natural' SOC restoration from bidirectional reserve provision.

3.1. Conservative and active strategy comparison

The simulated BESS operation results are illustrated in Fig. 6 with the Conservative strategy on the left and Active strategy on the right. The charts display the 'activated' BESS power for aFRR (orange area) and FCR (blue area) provision as well as the realised transactions in the ID market (grey area) for SOC restoration. The black line indicates the total power at which the BESS is operating, considering the net total activations in all the markets that the BESS participates at (for reserve provision and ID trade delivery). Consequently, the purple line depicts the dynamics of BESS SOC. The charts allow us to make two main observations on the implications of the Conservative (LER) and Active (non-LER) strategies.

First, we can observe that, in the Conservative strategy (left chart), the FCR power provided by the BESS is gradually reduced from the committed −8 MW to 0 MW. This is indicated by the interruptions in FCR activation (blue segments) on the left-side chart of Fig. 6 and is due to the algorithm behind the LER management module. Namely, after fulfilling the 30-minute $\Delta T_{\mathrm{minLER}}$ criterion, the BESS is (almost) exhausted and enters reserve mode.[18] Since there is a long-lasting power system alert state, the BESS needs to switch to reserve mode six times. Nevertheless, the LER still continues to provide the full committed aFRR capacity (−32 MW) without any interruptions since aFRR is not subject to any LER-specific alleviations. In total, the LER manages to provide 29 MWh of FCR energy, 192 MWh of aFRR energy, whereas the energy sold in the ID market to restore the SOC amounts to 151 MWh during 6 h shown in the left chart of Fig. 6.

The second observation is that the Active strategy (right chart), replicating a non-LER asset, ensures a full continuous FCR (−8 MW) and aFRR (−32 MW) activation. Here, the scheduled ID deliveries allow the BESS to fully counteract the reserve activations and thus the SOC remains at the maximum limit of 90 % without violating it. This is achieved by the BESS using the maximum available capacity for ID trading. The opposite ID trades (+40 MW) allow to negate the full reserve activation and eventually result in a stable SOC of 90 %. (In fact, the actual physical activation of the BESS is then 0 MW as shown by its total power of 0 MW (black line) on the right chart.) During the six-hour simulation period shown in the right chart of Fig. 6, the non-LER provides a total of 48 MWh of FCR energy, 192 MWh of aFRR, and the corrective ID sell trades amount to 169 MWh.

Based on the analysis of the extreme frequency deviation scenario, we can validate that, with the assumed BESS parameters, it is able to provide FCR both as a LER and as a non-LER resource (i.e. without the

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[17] Parameters are based on two BESS purchased by the Latvian TSO (20 MW / 40 MWh and 60 MW / 120 MWh) combined into a single equivalent unit.

[18] In this specific scenario, during reserve mode, the BESS provides 0 MW of FCR capacity because the short-term frequency deviation is 0 Hz due to the assumed continuous deviation of +0.2 Hz.

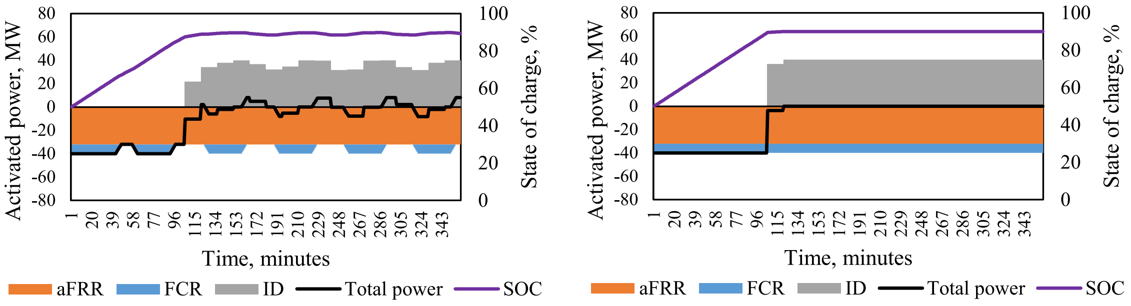

Fig. 6. BESS operation in a simulated 6-hour extreme scenario with Conservative (left) and Active (right) SOC management.

reserve mode) despite the harsh power system conditions. If it is qualified as a non-LER provider, according to the Active strategy, the BESS operator needs to schedule more active ID trades for SOC restoration compared to the Conservative strategy.

If we considered the option for the BESS to provide also voluntary aFRR energy bids in addition to the mandatory ones (as per the algorithm in Section 2.5), in this particular example, additional bids in the downward direction would be possible only at the beginning of the simulation time horizon, namely for the aFRR MTU from minute 30…45 with the GCT at minute 5, since by this time the SOC would had not yet deviated too far from its initial value. Instead, for the up-regulation, the BESS would be able to make more voluntary aFRR energy bids. This is because in our extreme unidirectional frequency deviation scenario the only aspects limiting upward bids is the BESS power earmarked for scheduled ID deliveries and priorly accepted voluntary aFRR bids, which are considered for the worst-case energy calculation. Thus, the total energy of voluntary aFRR bids would be 10 MWh for down-regulation for both LER and non-LER assets, which results from a single 15-min MTU with a maximum of 40 MW bid. For up-regulation, the total energy would be 49.75 MWh for a LER and 23.75 MWh for a non-LER. These results show that, when considering operation of a BESS in multiple markets at once or value-stacking, more benefit and contribution to power system reserves can be extracted from the BESS when providing aFRR if it is qualified as a LER for the FCR service. Still, from the TSO point of view, the LER status has additional implications, e.g. the need to replace the LER FCR provider with other reserves in case of reservoir exhaustion during long-lasting unidirectional frequency deviations.

3.2. *Impact of ID market GCT*

As a final step of the validation, we assess the impact of ID market GCT on the BESS operation with a sensitivity analysis by varying only the ID GCT (from 105 min to 15 min) with the rest of the input parameters remaining the same as before. The purpose of this analysis is to assess the sensitivity of BESS operation to changes in ID market design parameters. These settings can vary among different EU countries and can be also subject to changes in the future. Therefore, this appraisal is particularly important to find out how well our proposed strategy can handle shorter ID GCT, which currently is 60 min in the Baltics and can be much shorter in other EU countries. For completeness of the sensitivity analysis, we also check the performance of our BESS management strategy with larger GCT as it increases the uncertainty in BESS SOC restoration.

The results of sensitivity analysis are shown in Fig. 7 by illustrating the total energy charge and discharge (y-axis) per type of service provided by the simulated BESS within the same 6-hour extreme scenario as introduced in Section 3. The ID GCT varied from 105 to 15 min, simulated per 15 min increments, is depicted on the x-axis. This sensitivity analysis is performed both for a LER with Conservative management strategy (orange lines) and for a non-LER reserve provider with Active strategy (blue lines) in Fig. 7.

A key takeaway is that the larger the ID GCT is, the less a LER with a Conservative SOC recovery strategy is able to provide FCR as indicated by the reduced energy amount on the chart. This is a due to the LER occasionally switching to reserve mode, as a result of which the LER is activated much less than the non-LER asset. This is most evidently pronounced with longer ID GCTs (left part of the x-axis). On the other hand, with a short GCT of 15 min, the LER is able to provide full FCR activation for the entire 6-h extreme scenario. Importantly, aFRR is fully delivered regardless of the length of the ID GCT both by the LER and the non-LER asset.

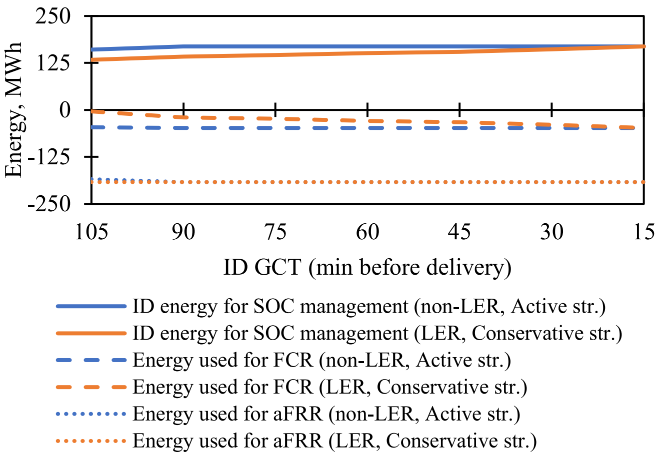

Fig. 7. Sensitivity analysis of the total energy charged to (−) and discharged (+) from the BESS to the grid in a 6-hour extreme scenario with varied ID GCT.

For a non-LER FCR (and aFRR) provider, only the largest considered GCT (105 min) caused issues as it failed to deliver both FCR amounting to 1.7 MWh of energy (of the expected 48 MWh) and aFRR amounting to 7.4 MWh of energy (of the expected 192 MWh). The failure to deliver this energy is due to the impossibility to schedule the first corrective ID trade soon enough due to the prolonged GCT. Under such circumstances, a BESS with a larger energy storage capacity would be required to fully guarantee reserve deliveries.

4. Simulated case studies

Having validated our SOC management strategy in a counterfactual worst-case scenario, we proceed to simulate the operation of a BESS with the same technical parameters and reserve types provided as in Section 3, albeit under realistic power system conditions for a duration of full year while providing reserves in multiple balancing markets with SOC restoration exclusively via ID market within the EU market framework. This allows us to analyse the main indicators of BESS operation in two distinct scenarios based on the available historical real-life data. Within our case studies, we assume a BESS qualified as a LER, providing FCR and aFRR, and we study it using either the Conservative or Active SOC management strategy. However, we do not consider voluntary aFRR energy bids, as the BESS in the case study is dimensioned so that it can cover all the required aFRR demand already with mandatory bids. The case study setup, data used in both scenarios and results are presented in the next subsections. The results focus, first, on the dynamics of the SOC trajectory and ID deliveries throughout the simulated year to show how the overall algorithm performs under realistic conditions. Next, we assess if and to what extent the selection of the SOC management strategy impacts the BESS operation. To remind, we already observed in Section 3 that under extreme conditions the selected strategy significantly affects the BESS operation. These differences are studied also from the perspective of corrective trade management in the ID market. Finally, a summary of the energy volumes traded in multiple markets versus the physical delivery is provided to showcase the BESS value-stacking opportunities enabled by the management strategy through mutual netting of multi-market activities. The results are presented separately for two distinct scenarios presented below which exemplify credible but diverse conditions of how the BESS studied in our paper might perform in the future Baltic power system.

4.1. Simulation input data

Since our study is motivated by the introduction of the Baltic balancing markets for FCR and aFRR in 2025, at the time of writing, there are no historical data available that could be used to simulate the realistic operation of a BESS within these markets based on actual real-life data. This is because previously the Baltic states have been relying on the Russian power system for the primary and secondary frequency control under the BRELL agreement [15]. Consequently, the historical frequency data are not representative of the future operational conditions of the Baltic power system within the CE synchronous area, and historical FCR and aFRR activation data is non-existent.

Because of this, we base our simulation case study on data from two different synchronous areas in Europe:

- for **Scenario 1**, we use data from Germany, which is relevant for the Baltic states since the Baltic power system will be synchronised with the CE synchronous area;
- for **Scenario 2**, we employ data from Finland, which, as a part of the smaller Nordic synchronous area, experiences more notable imbalances and frequency fluctuations.

According to SOG, the standard frequency range is ±100 mHz in the Nordic synchronous area vs ±50 mHz in CE. While the Baltic power system will be synchronised with CE, the overall larger frequency deviations as in FI might be reminiscent of the more volatile operation of the future Baltic power system. Initially, there will be a single synchronous connection to CE (Poland), hence there are increased risks of occasional operation in islanded mode due to planned maintenance or failure of this single interconnection. Thus, with these two scenarios, we aim to simulate and assess the operation of the BESS management algorithm under realistic but distinctive conditions.

To simulate reserve provision by the BESS, for **Scenario 1** we use and preprocess the following data:

- aFRR setpoints in Germany with 1 s resolution from 1 July 2022 to 30 June 2023 [32]: the data is first reshaped to 1 min resolution[19] by averaging and then scaled to match the expected maximum aFRR demand to be provided by the simulated BESS (i.e. the maximum aFRR setpoint is set to 32 MW, with the other values reduced proportionally); the specific time period selection was motivated by the frequency data availability only from the end of June 2022 in this data source[20];
- frequency measurements in Germany from 1 July 2022 to 30 June 2023 with a temporal resolution of 1 s and accuracy of 1 mHz [32]: the data is reshaped to 1 min resolution by averaging.

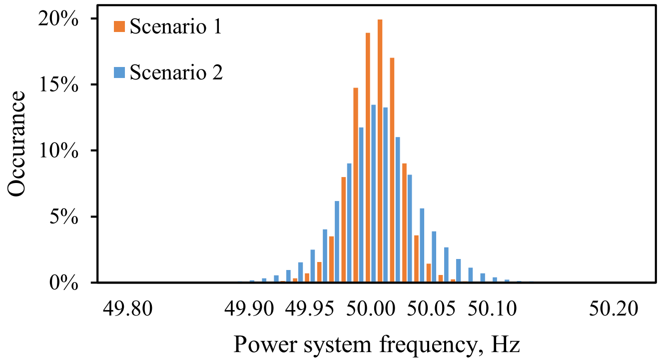

Fig. 8. Histogram of the frequency timeseries used in the simulated scenarios.

For **Scenario 2** we employ:

- activated aFRR energy in Finland in 2022 with 1 h resolution [33]: first, the downward and upward aFRR timeseries are summed with their signed values to obtain the net activated aFRR energy per timestep; second, the data is scaled to match the maximum expected aFRR demand to be provided by the simulated BESS the same way as for Scenario 1;
- frequency measurements in Finland in 2022 with 1 s resolution and 0.1 mHz accuracy [33]: the data is reshaped to 1 min resolution by averaging.

A comparison of the 1-year long input data of both scenarios with 1 min resolution is provided in Fig. 8 for the frequency timeseries and in Fig. 9 for the aFRR activations. It is evident from Fig. 8 that the frequency is indeed much more volatile in Scenario 2. The frequency deviation is within the FCR deadband of ±10 mHz for 38.8 % of minutes in Scenario 1 and only for 26.7 % of time in Scenario 2. The actual frequency range is 49.85…50.20 Hz in Scenario 1 and 49.77…50.22 Hz in Scenario 2. The standard deviation in both cases is 0.020 Hz and 0.034 Hz, respectively, which also exemplifies a more volatile frequency and overall larger FCR response required in Scenario 2. Based on the power system alert state criteria in CE, there would have been an alert state for a total of 242 min in Scenario 1 and 5813 min in Scenario 2, representing 0.05 % and 1.11 % of the 12-month simulation horizon, respectively. We must note though that the alert state parameters are in fact different in CE and Nordic synchronous areas [7], and in general harsher operational conditions are permissible in the Nordics due to the much smaller power system size and inherent larger volatility. However, in our simulations we adhere to the CE rules as we try to emulate potentially unsatisfactory and worsened operational indicators of the future Baltic power system in order to validate the robustness of our strategy.

The aFRR activations displayed in Fig. 9 also showcase a significantly increased need for balancing reserves in Scenario 2. The expected aFRR activation is 0 MW in 23.2 % of the simulation timesteps in Scenario 1 and only in 13.2 % in Scenario 2. The average activated reserve is −0.31 MW in Scenario 1 and − 3.54 MW in Scenario 2, meaning that in both

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[19] We run the simulations with 1 min resolution for simplicity and to reduce the computational burden since higher granularity is not necessary for our analysis and strategy validation purposes. Still, our simulation tool allows the user to set their preferred resolution.

[20] Additionally, the provision time of FRR energy was reduced from 4 h to 15 min as of 22 June 2022, hence we also used the resulting market data from July 2022 until June 2023 for the economic assessment, selecting the same period as for the frequency timeseries.

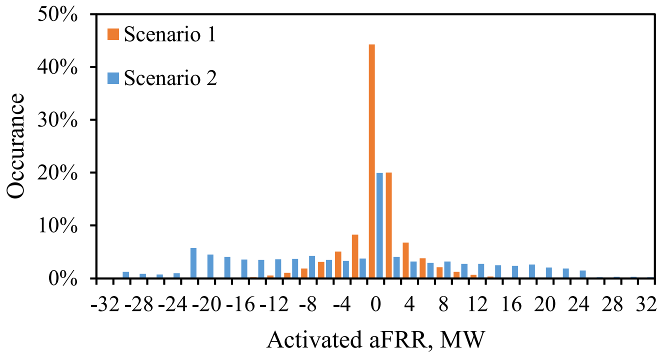

Fig. 9. Histogram of the aFRR activation timeseries used in the simulation scenarios.

scenarios there is an overall down-regulation bias, but it is more pronounced in the second scenario. The total expected activated aFRR energy is 5.6 times higher in Scenario 2 compared to Scenario 1 for down-regulation, and 3.7 times higher for up-regulation.

4.2. Simulation results of Scenario 1

4.2.1. SOC and ID trade dynamics during the year

In this subsection we present the simulation results of BESS operation in Scenario 1, which is characterised by comparatively smaller frequency deviations. We start by illustrating the resulting SOC trajectory of the BESS (Fig. 10) and the ID market trades scheduled (Fig. 11) during the simulated year, considering only the Conservative strategy of a LER FCR provider. In Fig. 10, we have also illustrated the time periods when there was a power system alert state (pink area) as they might imply alleviations for the LER.

We make two observations from these results. First, the behaviour of the SOC is overall very stable. It is persistently contained within a range of ~30…70 % in Fig. 10, and larger fluctuations occur rarely, rather in weekly cycles than daily or hourly ones, without ever approaching the SOC limits (10 % and 90 %). The second observation is that the BESS uses relatively small ID trades for SOC management. The ID transactions (Fig. 11) usually require less than a half of the total BESS power available for ID trading, which according to Eq. (7) and our assumptions from Section 3 is 40 MW. Moreover, there is evident stability in their direction: sequential ID trades are seldom in the opposite directions. Overall, this demonstrates the efficiency of the SOC management strategy as there are apparently no over-corrective actions and the transactions are scheduled on time to ensure smooth and energy-efficient SOC restoration via ID market.

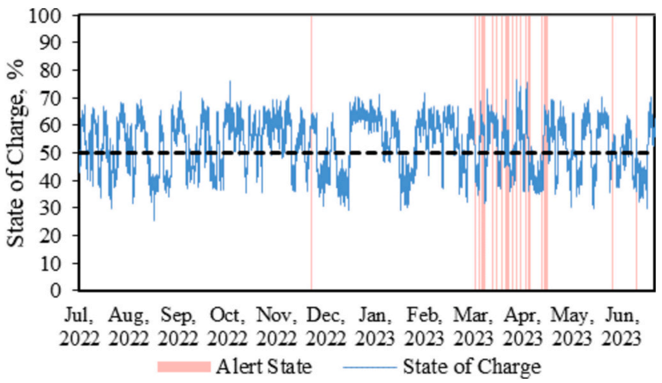

Fig. 10. BESS SOC trajectory with Conservative strategy during the simulated year (Scenario 1).

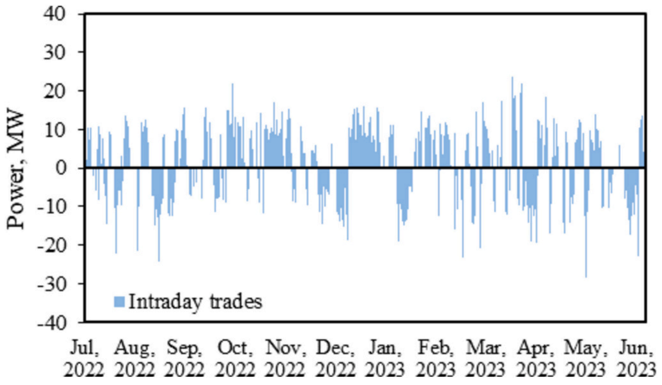

Fig. 11. BESS power delivered in the ID market with Conservative SOC management strategy during the simulated year (Scenario 1).

4.2.2. Impact of SOC management strategy

Next, we compare the statistical indicators of BESS operation in Scenario 1 with both the Conservative and Active SOC management strategy. (To remind, the Active SOC management strategy is similar to a non-LER FCR-provider.) The results show that in a realistic scenario, which is based on the historical frequency and reserve activation data, the two strategies have less pronounced differences in BESS operation compared to the counterfactual extreme scenario results in Section 3. The resulting indicators are summarised in Figs. 12–14 and Tables 2–4.

The histogram in Fig. 12 shows the distribution of the SOC levels BESS has had during the simulated year (calculated per 1 min timestep) with each strategy. Mostly, the BESS has been charged above 50 % regardless of the management strategy used, which is also confirmed by the median values reported in Table 2 (54.8 % and 53.9 %). The most important takeaway from the SOC statistics is that the Active strategy reduces SOC fluctuations as the SOC tends to, overall, be closer to the initial level of 50 %, and the standard deviation is slightly smaller than with the Conservative strategy (7.5 % vs 9 %).

Note from the histogram in Fig. 12 that there are two main clusters of SOC values that are more prevalent than others – in the range of 40 % to 45 % as well as 55 % to 65 %. This can be explained by the BESS reaching these values during corrective ID trades, because a correction closer to 50 % is not necessary, considering the assumed technical parameters of the BESS and the reserve requirements expected from it. Moreover, since the FCR and aFRR activations used as input for Scenario 1 are comparatively modest, the BESS SOC can evidently be situated within the above-mentioned ranges for prolonged periods of time.

Furthermore, we evaluate the distribution and volume of ID market trades scheduled for SOC restoration (Fig. 13 and Table 3). We can notice that the vast majority of transactions have a small volume (≤±4

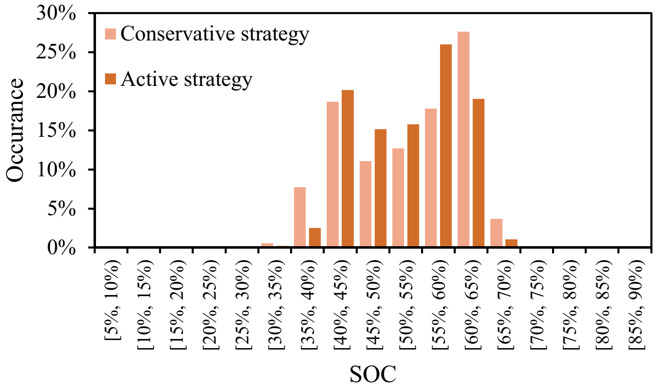

Fig. 12. Histogram of the BESS SOC level during the simulated year with both SOC management strategies (Scenario 1).

MW). Moreover, the largest actual BESS power used for ID market is 23.75 MW, which is far from the theoretically available 40 MW limit. When comparing the Conservative and Active strategy, the latter results in an almost 2 percentage point increase in the number of MTUs with an ID trade scheduled, with the total volume of traded energy increased by 5.9 % for electricity sale and by 9 % for purchase transactions.

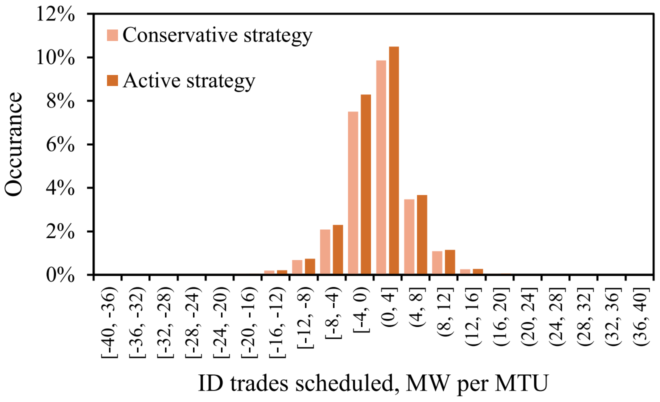

Fig. 13. Histogram of the scheduled ID trades for BESS restoration in the simulated year (Scenario 1), only nonzero values included.

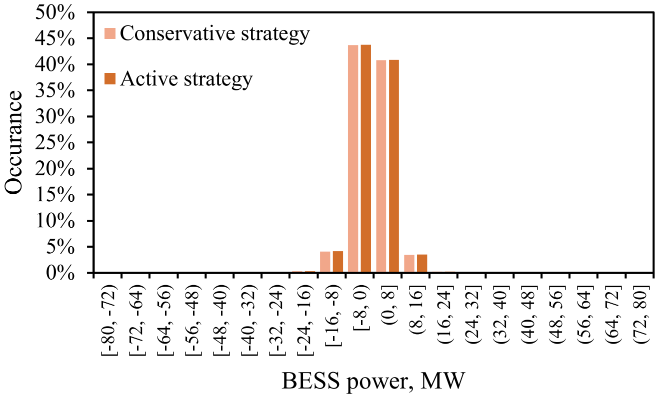

Fig. 14. Histogram of the BESS active power in the simulated year (Scenario 1), only nonzero values included.

Table 2
Statistical properties of the simulated BESS SOC (Scenario 1).

Indicator	Conservative strategy	Active strategy
Minimum	25.20 %	27.50 %
Maximum	76.47 %	74.41 %
Average	53.00 %	52.69 %
Median	54.78 %	53.91 %
st. dev.	9.00 %	7.46 %

Table 3
Statistical properties of the simulated ID trades (Scenario 1).

Indicator	Conservative strategy	Active strategy
MTUs with trades	25.31 %	27.28 %
Average trade	0.67 MW	0.62 MW
Minimum	−28.55 MW	−28.55 MW
Maximum	23.75 MW	23.75 MW
Sum of sell trades	4481 MWh	4746 MWh
Sum of buy trades	−2990 MWh	−3260 MWh

Note: Negative values imply a buy trade (for BESS charging).

Table 4
Statistical properties of the BESS active power (Scenario 1).

Indicator	Conservative strategy	Active strategy
Time with no activity	7.36 %	7.20 %
Minimum actual power	−34.49 MW	−34.49 MW
Maximum actual power	32.30 MW	32.30 MW
Total discharged energy	11,894 MWh	11,977 MWh
Total charged energy	−13,228 MWh	−13,316 MWh

Note: This includes FCR response, aFRR activations and ID trade delivery.

4.2.3. BESS trade netting and physical deliveries

Finally, we assess the actual BESS operating power, which is a sum of all the services the BESS is providing in every market at each timestep (Fig. 14 and Table 4). Evidently, the actual physical activity of the BESS is mostly quite minor compared to its theoretical capabilities. This is because the BESS is dimensioned to withstand the worst operating conditions, which do not emerge in the rather modest Scenario 1. We can also note that the Active strategy results in just barely more physical activity of the BESS compared to the Conservative strategy. For example, idle time of the BESS with Active strategy is decreased only by 0.16 percentage points, and the total energy exchange is increased by only 0.7 %. This is because the ID market transactions can counteract and (partially) net out BESS activations for reserve provision when they coincide, consequently reducing the actual energy input/output from the BESS.

This netting process is well-illustrated in Fig. 15 where we compare the physical net energy exchange of the BESS to the total amount of energy delivered in all the markets the BESS participates at. It is evident that the actual energy discharged and charged is less than the sum of the BESS deliveries for FCR, aFRR provision and ID market transactions in each direction. Namely, the sum of “discharge” deliveries is 15.3 GWh, whereas the actual physical discharge is 11.9 GWh (22.4 % less). For BESS charging the respective values are 16.7 GWh vs 13.2 GWh (20.6 % less). This demonstrates the added value of simultaneous BESS participation in multiple markets, and also validates the ability of our SOC management strategy to ensure successful value-stacking of the BESS, while ensuring compliance with the market rules and TSO requirements towards reserve providers.

4.3. Simulation results of Scenario 2

4.3.1. SOC and ID trade dynamics during the year

In this section we assess the simulation results for Scenario 2 in the same order as was done for Scenario 1 in Section 4.2 and analyse the resulting similarities and differences. As expected, Scenario 2 with more volatile frequency fluctuations and higher demand for FRR compared to Scenario 1 requires a lot more activity from the BESS, which is reflected in both the much more fluctuating dynamics of the SOC (Fig. 16) and the more frequent and overall larger volume of ID market trades (Fig. 17). We can also observe many occurrences of system alert state (pink areas in Fig. 16), as already explained in Section 4.1. Thus, unlike the previous example, this scenario requires the BESS operating as a LER FCR

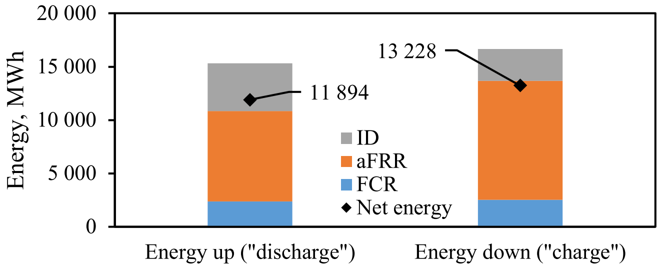

Fig. 15. BESS energy delivered for reserve provision and ID market vs physical energy exchange (Scenario 1, conservative strategy).

provider (with the Conservative strategy) to use also the ‘recovery’ status, granted exclusively to LERs following an alert state. The simulated BESS has been in ‘recovery’ status in 19 instances for a total of 242 min of the year. However, only once it has required the BESS to switch to FCR provision in reserve mode, which lasted 11 min. We can note that the average time of ‘recovery’ has been 12.7 min, which is much less than the theoretical maximum of 2 h allowed by SOG. Instead, if the BESS operates with the Active strategy, it does not need to use any recovery time at all in Scenario 2, and likewise we observe no switching to reserve mode in the simulations. Interestingly, despite the significantly more volatile activity in the ID market compared to Scenario 1 results, we still do not observe over-corrective trades (i.e., having to submit an ID offer in the opposite direction to the one in the previous MTU). A sudden and high-volume change in the power system imbalance direction would likely be required to experience an over-corrective trade from our algorithm.

4.3.2. *Impact of SOC management strategy*

The resulting indicators of SOC and ID trade dynamics from Scenario 2 simulations using both the Conservative and Active SOC management strategy are summarised in Figs. 18–20 and Tables 5–7. If we compare the SOC levels of the BESS during the simulated year, in Scenario 2 they are more scattered (Fig. 18) than in Scenario 1 (Fig. 12) and tend to more closely approach both the minimum and maximum permissible level. Generally, the simulated SOC values in Scenario 2 are more resemblant of the normal distribution. Still, also in Scenario 2 the BESS charge level is mostly above 50 %, which is confirmed by the median values reported in Table 5 (58.7 % and 57.3 %). The same as before, the Active strategy reduces SOC fluctuations: the values are slightly closer to the initial 50 %, the minimum and maximum range is lower, and the standard deviation is decreased.

It bears repeating that, based on the input data from Section 4.1, in Scenario 2 the balancing energy required for FCR and aFRR is overall much larger, and there is even more pronounced down-regulation bias.

When assessing the ID market trades for SOC restoration (Figs. 17, 19 and Table 6), we notice that the total energy content of scheduled transactions increases more than six times in Scenario 2. The largest values of traded power are now approaching the limit of 40 MW, which is the theoretically available power for ID market. The largest ID transaction is 36.5 MW in this scenario. When comparing the two strategies, the Active SOC management results in 4 percentage point more MTUs with an ID market trade scheduled compared to the Conservative strategy, while the total volume of transactions increases by 6.2 % for electricity sale and by 20.9 % for purchase trades.

4.3.3. *BESS trade netting and physical deliveries*

When we analyse the actual BESS operating power, similarly to Scenario 1, the Active strategy exhibits only marginally more physical activity of the BESS compared to the Conservative strategy (Fig. 20 and Table 7). Namely, idle time of the BESS is 0.06 percentage points lesser with the Active strategy and the total energy exchange increases by only 0.60 %.

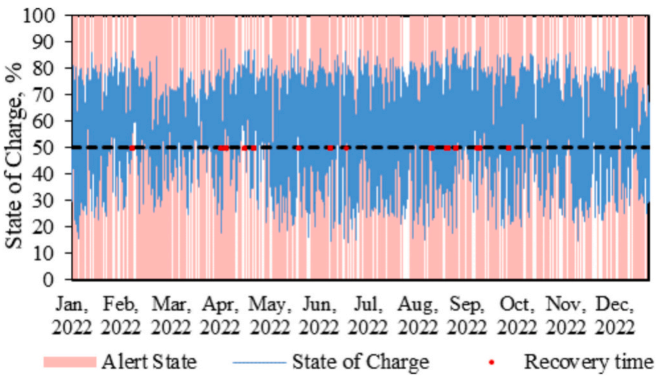

Fig. 16. SOC trajectory with Conservative SOC management strategy during the simulated year (Scenario 2).

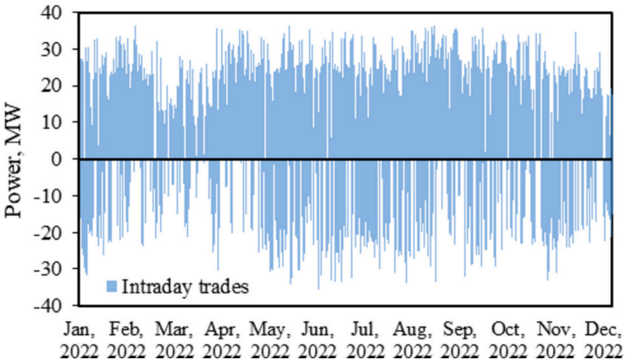

Fig. 17. Power to fulfil the scheduled ID deliveries with Conservative SOC management strategy during the simulated year (Scenario 2).

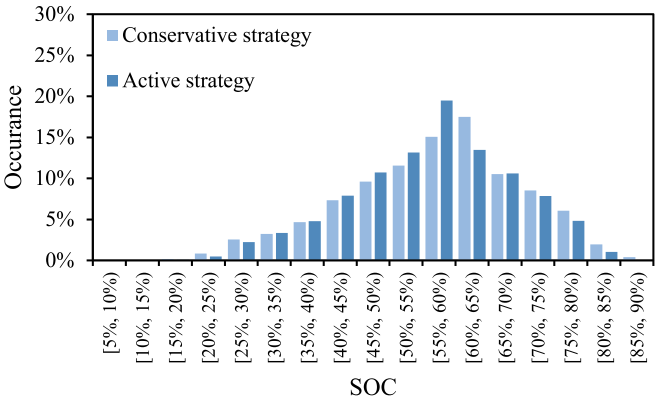

Fig. 18. Histogram of the BESS SOC levels during the simulated year with both SOC management strategies (Scenario 2).

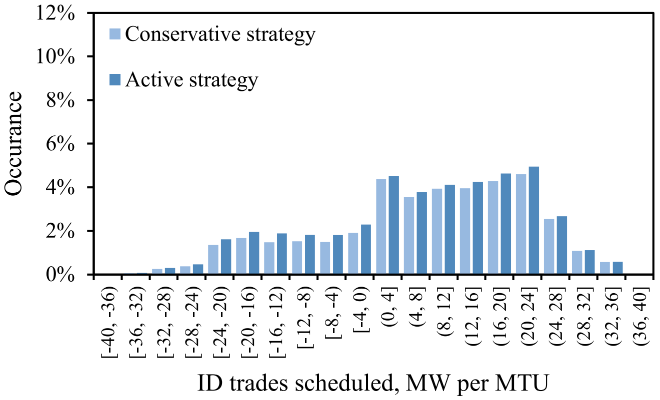

Fig. 19. Histogram of the scheduled ID trades for BESS restoration in the simulated year (Scenario 2), only nonzero values included.

Thereby, even though the two scenarios we simulated are designed with distinct operational conditions (in terms of power system frequency deviations and reserve activations), the comparison of the Conservative and Active strategies allows drawing similar conclusions in both scenarios. Namely, a key observation is that the specific regulatory conditions applicable to LER FCR providers play a minor role during power system normal state with the regular operation of the BESS in reserve markets. The most significant impact of the SOC management strategy

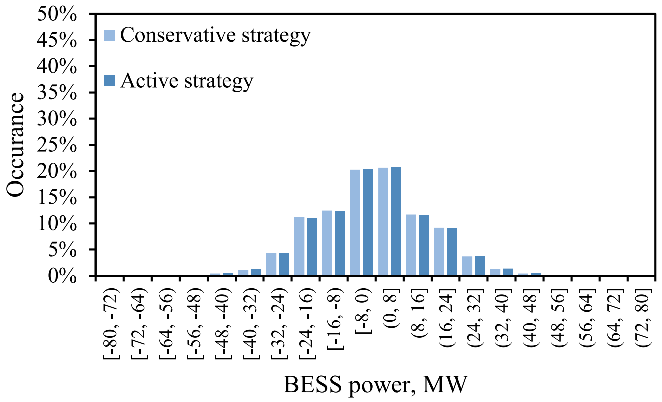

Fig. 20. Histogram of the BESS active power in the simulated year (Scenario 2), only nonzero values included.

Table 5
Statistical properties of the simulated BESS SOC (Scenario 2).

Indicator	Conservative strategy	Active strategy
Minimum	13.86 %	16.15 %
Maximum	88.27 %	86.21 %
Average	56.98 %	56.12 %
Median	58.66 %	57.34 %
St. Dev.	13.25 %	12.39 %

Table 6
Statistical properties of the simulated ID trades (Scenario 2).

Indicator	Conservative strategy	Active strategy
MTUs with trades	39.03 %	42.87 %
Average trade	7.51 MW	6.83 MW
Minimum	−35.64 MW	−35.64 MW
Maximum	36.47 MW	36.47 MW
Sum of sell trades	36,786 MWh	39,068 MWh
Sum of buy trades	−11,094 MWh	−13,409 MWh

Note: Negative values imply a buy trade (for BESS charging).

Table 7
Statistical properties of the BESS active power (Scenario 2).

Indicator	Conservative strategy	Active strategy
Time with no activity	2.75 %	2.69 %
Minimum power	−61.64 MW	−61.64 MW
Maximum power	58.35 MW	58.35 MW
Total discharged energy	49,119 MWh	49,409 MWh
Total charged energy	−54,484 MWh	54,809 MWh

Note: This includes FCR response, aFRR activations and ID trade delivery.

selected was observed in the extreme scenario (Section 3), but it was rather negligible in the real-world data based scenarios in Section 4. We must also note that this is partly due to the simulated BESS providing four times larger aFRR capacity compared to FCR, and under current regulation only FCR provision is impacted by the BESS LER status. Thus, the outcomes might be different if the share of FCR provision by the BESS would increase.

Finally, we summarize the traded energy and physical energy deliveries of the BESS during the simulated year in Scenario 2 (Fig. 21). Comparing to Scenario 1 (Fig. 15), it can be noticed the physical energy exchange is more than four times larger in Scenario 2. Thus, the BESS encounters 74 and 307 full cycle equivalents in Scenario 1 and 2, respectively. We can again observe that our proposed SOC management strategy enables the BESS to continuously serve several markets and products during the whole simulated year while efficiently reducing the physical energy required compared to the total net deliveries in all the markets.

5. Economic assessment

Building on the technical simulation results in Sections 4.2 and 4.3, we continue by estimating the economic indicators of BESS operation with our proposed management strategy in the two distinct realistic operational scenarios. While the approach described in this paper is not focused on profit-maximisation, rather striving to ensure the robustness of reserve provision, nevertheless for feasibility purposes it is important to make sure that it is capable of providing an overall positive cash flow. Furthermore, we strive to compare the potential SOC restoration costs in the ID market to benefits obtainable from reserve provision.

5.1. Input data and methodology

While our devised strategy for the BESS operational management has been based on the expected Baltic balancing market framework, which is aligned with the EU balancing market harmonisation, there was no real-world data available during our study since the Baltic market for FCR and aFRR is set to launch in 2025. Therefore, to provide an indicative economic assessment for the proposed BESS management strategy, we use the balancing market data from Germany and Finland. For market prices, the same period as for the frequency timeseries is selected: 07/2022–06/2023 for Germany (DE) and the year 2022 for Finland (FI). Namely, the following price data from DE are used for Scenario 1:

- marginal FCR capacity settlement price (€/MW for each 4-hour period) [34];
- the imbalance caused by FCR activation is settled using the uniform imbalance price (reBAP, €/MWh for each 15-min MTU) [35]. The respective (net) energy amount and imbalance direction is derived by summing the FCR activations during the MTU [19];
- weighted average aFRR capacity price (up/down, (€/MW)/h for each 4-hour MTU) [34];
- weighted average aFRR energy price (up/down, €/MWh for each 15-min MTU).

The following price data from FI [33] are used for Scenario 2:

- marginal FCR-N capacity price (€/MW) for each 1-hour MTU. As the Finnish TSO did not procure the hourly FCR-N in all MTUs, during the respective hours (4.6 % of the year) we use the yearly FCR-N price instead (12.24 €/MW in 2022 [36]) resulting in the average price of 36.40 €/MW/h used for our assessment;
- marginal aFRR capacity price (up/down, €/MW) for each 1-hour MTU. As the Finnish TSO procured the aFRR capacity only during certain hours, for the remaining part (18.5 % hours in 2022) we use a price of 0 €/MW, meaning the aFRR capacity is not remunerated;

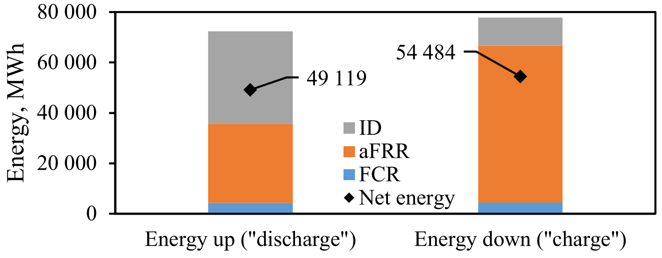

Fig. 21. BESS energy delivered for reserve provision and ID market vs physical energy exchange (Scenario 2, Conservative strategy).

- while the imbalance resulting from reserve activation (incl. FCR-N) is corrected for the respective balance responsible party (BRP), the balancing energy resulting from the activation of both FCR-N [37] and aFRR [38] is settled using the hourly balancing energy market price [20], which is defined the same as for mFRR (separately for up- and down-regulation, €/MWh). E.g. for FCR-N up-regulation, the average under-frequency deviation during each 15-min imbalance settlement period (ISP) is used to calculate the payment (together with the committed and verified FCR-N capacity), and similarly also for down-regulation during the same ISP. In our case, we calculate the FCR-N energy based on the average 1-min frequency deviation and aFRR energy based on the hourly activated volume, which is then multiplied by the respective ISP's balancing energy price.

We calculate the income from the contracted FCR and aFRR capacity based on the capacity price both in DE and FI. In addition, the income from the energy sold to the grid and the cost of energy purchased thereof is estimated based on the energy price of the activated aFRR, imbalance energy volume and price (for FCR in DE) and the activated FCR volume and balancing energy price (for FI).[21] This reflects the assumption of BESS participating in both aFRR capacity and energy market, although taking part in energy-only market is also possible by submitting the so-called ‘voluntary’ or ‘free’ bids. In fact, this implicitly corresponds to the simulated time periods when no aFRR capacity was procured in FI and only aFRR energy was remunerated when provided.

Since the aFRR energy in DE is settled based on the pay-as-bid pricing (in contrast to the uniform price in FI), we used the weighted average 15-min price of the accepted bids published by the TSOs for the positive and negative aFRR energy respectively. For example, during the considered period (07/2022–06/2023) the weighted average price for the positive aFRR energy was 1585.38 €/MWh and −1037 €/MWh for the negative aFRR energy (in which case the grid operator pays to the reserve provider for the energy consumed from the grid). The average price is affected by the bidding behaviour: often there are offers up to the DE price cap in both directions (±15,000 €/MWh).

We use the DA market price [39] for DE and FI as an indicator to estimate the value of ID trade in each scenario by also distinguishing two cashflows: sale and purchase of ID energy. The DA price was chosen since the largest amount of ID trade takes place in a continuous market, settled based on pay-as-bid pricing, and the ID market result timeseries (e.g. the weighted average price) are not freely available as open data. Indeed, previous studies have confirmed there is a strong correlation between prices in DA and ID markets, although ID prices tend to be more volatile [40,41].

5.2. Results

The estimated annual cash flow for both strategies and scenarios is presented in Figs. 22–23. The total revenue is obtained by summing all the income components and deducting the cost of energy purchased by the BESS operator such as the downward aFRR and FCR energy, negative FCR-caused imbalance and ID energy bought. In Scenario 1 though the cost of purchased aFRR energy is negative meaning that the TSO pays to the BESS operator instead. This is due to the negative weighted average aFRR downward energy price during the period considered and could lead to an overestimation of the income.

In both scenarios the income from FCR capacity is comparable, although it is almost twice as large in Scenario 2 since in Finland the hourly FCR capacity price was 36.40 €/MW vs 19.41 €/MW in Germany. In both cases, the income from aFRR provision is larger than from FCR, albeit due to different reasons. In Scenario 1, it is merely related to the four times larger capacity provided by the BESS to the aFRR market compared to FCR (the average aFRR capacity price was 14.74 €/MW per hour, 24 % less than for FCR in DE). Instead, in FI the aFRR price (108 €/MW) was three times larger than that of FCR resulting in >24 times larger income from aFRR capacity in Scenario 2.

As concerns the FCR-related energy, both scenarios result in a positive cash flow even though the net energy flow is negative (overall slightly more energy bought than sold). In Scenario 1, the net annual income is 0.17 M€, while in Scenario 2 it is 0.22 M€. This is due to the much larger price of imbalance or balancing energy sold by the BESS to the TSO compared to that of the purchased energy. Namely, in DE the average price was 180.37 and 103.15 €/MWh for the positive and negative imbalance, respectively. Similarly, in FI the price was 168.47 and 114.23 €/MWh for the up- and down-regulation energy, respectively.

Despite the potential overestimation of income from aFRR energy transactions in Germany, the total estimated income from aFRR provision in Scenario 2 is almost twofold than that of Scenario 1, which can be mostly attributed to the larger aFRR capacity remuneration. It must be noted that in Finland, a uniform market price is used while in Germany the pay-as-bid approach is implemented. One should also take into account the high sensitivity of results to the assumptions used. While we employed the 2022 prices for Finland, e.g. in 2021 the aFRR capacity price was twice lower instead (41.7 €/MW).

In both scenarios, the energy volume sold on the ID market is larger than ID buy trades. However, only in Scenario 2 the net ID trade cash flow is positive. In Scenario 1, it is slightly negative due to a larger average price during the ID buying transactions compared to the sale trades. Altogether, in our simulation examples, the ID market transactions for SOC management constitute a comparatively minor share of the overall cash flow. Importantly, the results allow identifying the positive financial impacts from providing multiple reserve products at once.

Although the overall income of our simulated BESS (with 80 MWh/160 MW capacity) can be considered rather large, we must note that the cash flows obtained reflect in fact the theoretical maximum value the BESS could gain when participating in the multiple markets considered. Based on our assumptions, we simulated the BESS as the only reserve provider covering all the demand of FCR and aFRR, which is an overestimation. This is because the overarching goal was to develop and validate a robust SOC management strategy, thus requiring to activate the BESS as much as possible. In the Baltic balancing market, it is expected that the specific TSO-owned BESS would be providing reserves only as a back-up source when there are insufficient reserve offers from market participants.

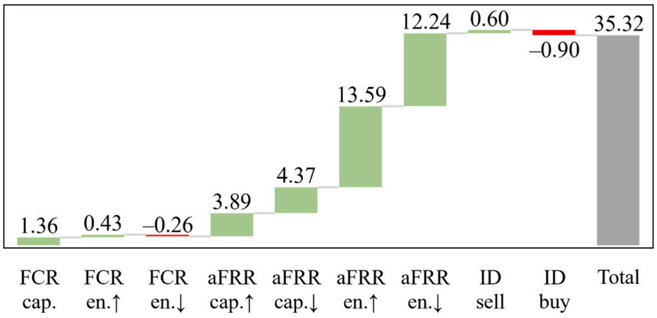

Fig. 22. BESS cash flow estimate (M€) with Conservative strategy, Scenario 1.

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[21] FCR provision often creates an imbalance because the mean frequency during an ISP is not always 50 Hz. The implications of different DOF measures on the imbalance volume and costs due to the FCR provision in Germany are analysed in [19]. In contrast, in Finland the BRP's imbalance is corrected [37], and the FCR provider is subject to a balancing energy settlement based on all the up- and down-regulation activations during each ISP [20].

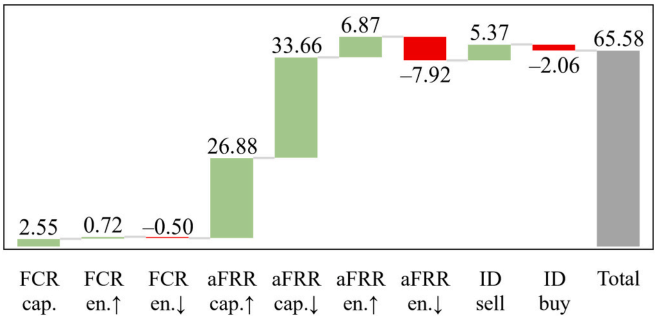

Fig. 23. BESS cash flow estimate (M€) with Conservative strategy, Scenario 2.

6. Conclusion

The robustness of the BESS management strategy presented in this study has been validated by simulating an extreme worst-case power system frequency deviation scenario. During such long-duration unidirectional frequency deviations, our proposed SOC management strategy ensures full provision of the committed reserves (FCR, aFRR) by the BESS, either qualified as a LER FCR provider or as a non-LER, with ID market-based SOC restoration. The devised strategy also demonstrates successful and efficient operation of the BESS under realistic power system operational conditions. Remarkably, our proposed algorithm enables simultaneous provision of multiple services by the BESS (FCR and FRR) with SOC recovery exclusively via scheduled transactions in the ID market, thus enabling efficient value-stacking for an independently operating BESS within European market framework.

The strategy implements the regulatory conditions for reserve-providing BESS applicable in harmonised European balancing markets and is adaptable to minute differences in specific provisions implemented by the TSOs in different countries. Two strategies for SOC management are offered in the paper. Conservative strategy takes advantage of the more lenient criteria applied to FCR-providing units qualified as LERs, whereas the Active strategy is aimed at a non-LER BESS participation in reserve markets, which operates on an equal footing with conventional reserve providers. The different outcomes of both approaches are most evident in worst-case scenarios, whereas during normal power system operation there are miniscule differences, which slightly increase in the scenario with larger frequency deviations.

The simulation case studies presented in this paper are based on the BESS that is expected to participate in the Baltic balancing markets for FCR and aFRR. However, as these markets are introduced only in 2025, there were no historical data from the Baltics that could be used at the time of this study. Instead, we rely on German and Finnish data representing two different synchronous areas in Europe in order to simulate two distinct possibilities of future operational conditions in the Baltic states following their synchronisation with CE in 2025. The results obtained successfully demonstrate technical feasibility and regulatory compliance of the proposed SOC management strategy. Moreover, the indicative economic assessment shows an overall positive operational cash flow achievable by the BESS from participation in the FCR and aFRR balancing markets with SOC restoration via the ID market.

The simulation tool developed within this study could be further used to research the impact various changes in reserve or wholesale market design might have on the operation of existing BESS. The tool is also useful to simulate and validate the feasibility of a specific set of technical parameters for new prospective BESS installations under different regulatory conditions within the European market framework. Moreover, we plan to expand the utility of the proposed robust BESS management strategy to also enable a profit maximisation motif with reserve capacity bid allocation in conjunction with day-ahead bidding as well as a functionality for additional ID bid preparation in addition to SOC restoration. This feature can be built on the basis of the voluntary FRR bid algorithm studied in this paper.

CRediT authorship contribution statement

Kārlis Baltputnis: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Zane Broka:** Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Formal analysis, Data curation, Conceptualization. **Gunārs Cingels:** Validation, Methodology, Conceptualization. **Aigars Sīlis:** Project administration, Methodology, Conceptualization. **Gatis Junghāns:** Supervision, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available on request.

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